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

2010 BPA Rate Case
Wholesale Power Rate Initial Proposal

SECTION 7(b)(2) RATE TEST STUDY

February 2009

WP-10-E-BPA-06

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WP-10 SECTION 7(b)(2) RATE TEST STUDY

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COMMONLY USED ACRONYMS

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

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

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

NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	BPA Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert

TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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1. INTRODUCTION

Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(b)(2), directs the Bonneville Power Administration (BPA) to conduct, after July 1, 1985, a comparison (hereafter called the Rate Test) of the projected amounts to be charged for general requirements power sold to its public body, cooperative, and Federal agency customers, over the Rate Test period plus the ensuing 4 years, with the power costs (hereafter called rates) to such customers for the same time period if certain assumptions are made. The effect of this Rate Test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from costs resulting from certain provisions of the Northwest Power Act. The Rate Test can result in a reallocation of costs from the loads of Priority Firm Power (PF) preference customers to other BPA power sales. BPA has codified the procedures to conduct the Rate Test in the *Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act* (*Implementation Methodology*), which, in turn, relies on BPA's legal interpretation of section 7(b)(2), as set forth in the *Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act* (*Legal Interpretation*).

The Rate Test involves the projection and comparison of two sets of wholesale power rates for the general requirements of BPA's public body, cooperative, and Federal agency customers (collectively, the 7(b)(2) Customers). The two sets of rates are: (1) a set for the rate period and the ensuing four years assuming that section 7(b)(2) is not in effect (i.e., the "projected amounts to be charged for firm power," known as Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (i.e., the "the power costs for general requirements," known as 7(b)(2) Case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the Program Case rates prior to

the rate comparison. Next, each nominal rate is discounted to the beginning of the test period of the relevant rate case. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest hundredth of a mill for comparison. If the simple average of the Program Case rates is greater than the simple average of the 7(b)(2) Case rates, the Rate Test triggers. The difference between the average of the Program Case rates and the average of the 7(b)(2) Case rates is used to determine the amount of costs to be reallocated from the 7(b)(2) Customers to other BPA power sales for the rate period.

1.1 Purpose and Organization of Study

The purpose of this Study is to describe the application of the *Implementation Methodology* and the results of such application. The accompanying Section 7(b)(2) Rate Test Study Documentation (Documentation), WP-10-E-BPA-06A, contains the documentation of the computer models and data used to perform the Rate Test.

This Study is organized into three major sections. The first section provides an introduction to the study, as well as a summary of the *Legal Interpretation* and the *Implementation Methodology*. The second section describes the methodology used in conducting the Rate Test. It provides a discussion of the calculations performed to project the two sets of power rates that are compared in the Rate Test. The third section describes the forecast of exchanging utilities' average system costs (ASCs). The fourth section presents a summary of the results of the Rate Test for the Initial Proposal. There are seven appendices to the study. Appendix A – Financing Analysis, provides documentation for the financing benefit assumptions. Appendix B – 7(b)(2) Resource Stack, provides an example of the resource stack, GDP inflator/deflator tables, and documentation in support of the accounting and financing treatment of the expensed portion of conservation resource costs. Appendix C – Non-Conservation Resources, provides documentation for the amount and costs of non-conservation resources in the resource stack.

Appendix D – Conservation Resources, provides documentation for the amount and cost of conservation resources in the resource stack. Appendices E, F, and G provide additional information regarding the ASC forecasts for FY 2010-2015. Appendix E presents summary tables; Appendix F presents forecast costs, load, and ASCs; and Appendix G presents forecast purchase power and sales for resale. There are also two attachments to the Study. Attachment 1 is the current *Legal Interpretation*. Attachment 2 is the current *Implementation Methodology*, with proposed changes shown in red-line markup.

1.2 Basis of Study

1.2.1 Legal Interpretation

Prior to the first phase of the 1985 general rate case, BPA published the *Legal Interpretation of Section 7(b)(2) of the Northwest Power Act*, 49 Fed. Reg. 23,998 (1984) (*1984 Legal Interpretation*). The *1984 Legal Interpretation* was revised as part of the WP-07 Supplemental rate proceeding. A short summary of the *Legal Interpretation* follows.

- The 7(b)(2) Case is modeled by limiting the differences between the Program Case and the 7(b)(2) Case to the five assumptions specified in section 7(b)(2) and the secondary effects of those assumptions, and reflecting the effects of those assumptions on the ratemaking processes, which otherwise remain the same between the Program Case and the 7(b)(2) Case.

- BPA will reallocate costs resulting from the rate test trigger, pursuant to section 7(b)(3) of the Northwest Power Act, in a manner that is consistent with section 7(a) of the Northwest Power Act.

- Applicable 7(g) Costs are excluded from the Program Case and the 7(b)(2) Case rates before those rates are compared. Applicable 7(g) Costs are excluded from the Program Case rates by an explicit subtraction. Applicable 7(g) Costs are excluded from the 7(b)(2) Case rates by not being included in the 7(b)(2) Case revenue requirement.

- "Within or Adjacent" DSI Loads are assumed to be served by 7(b)(2) Customers for the entire rate test period.

- "Within or Adjacent" DSI Loads assumed to be served by 7(b)(2) Customers are assumed to be served wholly with firm power.

- Appendix B to S. Rep. No. 272, 96th Cong., 1st Sess. (1979), is used to determine which DSI Loads are "Within or Adjacent" to 7(b)(2) Customer service areas, with modifications to reflect the actual status of BPA service to the DSIs or a change of situation in local service area or electrical connection.

- To determine "Federal Base System (FBS) resources not obligated to other entities," DSI Loads not "Within or Adjacent" are assumed to receive service from non-7(b)(2) Customers.

- Section 7(b)(2)(D) identifies three types of additional resources that are assumed, in the 7(b)(2) Case, to meet the 7(b)(2) Customers' loads after FBS resources are exhausted. Specific additional resources are assumed to be used in the order of least cost first; generic resources are then used if necessary.

1.2.2 Implementation Methodology

A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on section 7(b)(2) implementation issues. The section 7(i) hearing was held as the first phase of the 1985 general rate proceeding. The issues resolved in the hearing are set forth in the *Administrator's Record of Decision for Section 7(b)(2) Implementation Methodology* (7(b)(2) ROD), published in August 1984, and are reflected in the adopted *Section 7(b)(2) Implementation Methodology (1984 Implementation Methodology).* The *1984 Implementation Methodology* was revised as part of the WP-07 Supplemental rate proceeding and adopted in the *2007 Supplemental Wholesale Power Rate Case Administrator's Final Record of Decision*, WP-07-A-05 *(2007 Supplemental ROD).* The major issues resolved in the 7(b)(2) ROD, as modified in the *2007 Supplemental ROD*, are discussed below.

- Reserve benefits provided under the Northwest Power Act are quantified using the same value of reserves analysis used in the relevant rate case, modified to reflect the assumption that "Within or Adjacent" DSI Loads may be less than the total amount of DSI Loads served by BPA. The *Implementation Methodology* allows for reserves from sources other than DSIs subject to the criteria listed therein.

- Financing benefits in the 7(b)(2) Case are quantified for planned or existing Type 1 resources (see explanation of resource "types" in Section 2.1.2.2) that have been acquired by BPA or are planned to be acquired in the Program Case during the Rate Test period. Financing benefits for existing Type 1 non-conservation resources that received a financing benefit associated with having a BPA acquisition contract when constructed and originally financed are separately identified for these specially termed "Named Resources." The financing benefits in the 7(b)(2) Case are prepared by BPA's financial advisor for the 7(b)(2) Rate Test, Public Financial Management, which estimates the resource sponsor's financial cost for the 7(b)(2) Case resources assuming that BPA did

not acquire the resource output. The current financing study (Appendix A) and past financing studies have made the simplifying assumption that a Joint Operating Agency (the resource(s) sponsor) would be formed to undertake the resource acquisitions for the 7(b)(2) Customers, with membership consisting of the region's 7(b)(2) Customers. The composition of the membership and the credit ratings of the individual members are contained in Attachment A to Appendix A, the financing study. BPA would contract with the JOA in the 7(b)(2) Case to provide the additional resources assumed in the 7(b)(2) Case. Without the financing benefits that are present in the Program Case, the resources required to meet the 7(b)(2) Customers' loads in the 7(b)(2) Case could be more expensive.

- Non-conservation Type 1 and Type 2 resources that are already constructed and financed and that did not receive any financing benefit associated with having a BPA acquisition contract when constructed do not have their financing costs changed by the financing study. Financing costs in the 7(b)(2) Case are quantified for planned or existing Type 2 resources that are owned or purchased by 7(b)(2) Customers but are not committed to load pursuant to section 5(b) of the Northwest Power Act. When ownership of a resource is by non-preference customers, or is unidentifiable (Type 3 resources), the *Implementation Methodology* states that the financing benefits analysis does not apply.

- Secondary effects result from reflecting the five specific section 7(b)(2) assumptions in the 7(b)(2) Case rates while keeping all the underlying ratemaking premises and processes the same for both Cases. Two secondary effects are identified for possible modeling in the Rate Test: the level of surplus firm power available, and the amount of marketed secondary energy.

- The Rate Test in this rate case is conducted using a single automated Excel® spreadsheet called RAM2010. The outputs of this spreadsheet model are in the Documentation, WP-10-E-BPA-6A, Section 2. The sequence of steps used to conduct the Rate Test is outlined below in Section 2.1.

- The projected rates for each year of the rate test period are discounted back to the beginning of the rate proposal test period using factors based on BPA's projected borrowing rate for each of the Rate Test years. The discounted rates then are averaged for each Case and the result rounded to the nearest hundredth of a mill. The Rate Test triggers if the simple average of the discounted rates for the Program Case exceeds the simple average of the discounted rates for the 7(b)(2) Case by one-hundredth of a mill or more. If the Rate Test triggers, the difference between the two rates is multiplied by the projected energy billing determinants of PF Preference customers in the rate period to determine the amount of costs to be reallocated from PF Preference customers to all other power sales.

2. METHODOLOGY

Implementing the Rate Test consists of incorporating the determinations from the *Legal Interpretation* and *Implementation Methodology* into the RAM2010 model.

2.1 Sequence of Steps

The Rate Design steps of RAM2010 carry out BPA's ratemaking process by performing the steps needed to develop wholesale power rates that are used as the Program Case for the Rate Test. The 7(b)(2) Case steps of RAM2010 carry out BPA's ratemaking process with changes to reflect the five 7(b)(2) assumptions.

2.1.1 Program Case in RAM2010

RAM2010 calculates annual Program Case rates for the WP-10 rate period (FY 2010-2011) and the following four years, FY 2012-2015. The method of calculating rates and the data used to calculate rates for the Program Case of the Rate Test are identical to those used in calculating the actual proposed rates for the two-year rate period. For the following four years, the Program Case uses the same method of calculating rates as for the rate period, and data that is consistent with data used for the rate period.

2.1.1.1 Sales

The sales forecast used to develop rates for the Program Case covers the period FY 2010-2015, and is the same forecast used to develop BPA's proposed rates. Sales forecasts were developed for the region's consumer-owned utilities (COUs) by aggregating utility-specific forecasts for those customers. The forecast Residential Exchange Program (REP) retail loads were provided by the utilities and verified by BPA's load forecasters. *See* Loads and Resources Study,

WP-10-E-BPA-01, Section 2.2.6. For purposes of the Rate Test, this study is forecasting the sale of a limited amount of power to the DSIs under the Industrial Firm Power (IP) rate schedule. Sales to Federal agencies and other contractual sales are entered into RAM2010.

BPA's total sales obligations are comprised of COU, investor-owned utility (IOU), DSI, Federal agency, REP, and Firm Power Products and Services (FPS) contractual sales. All PF, IP, and New Resource Firm Power (NR) forecast sales are entered into RAM2010 with diurnally and monthly differentiated energy and monthly differentiated demand billing determinants. Documentation for these forecasts of regional power loads appears in the Loads and Resources Study, WP-10-E-BPA-01, Section 2.2, and Documentation, WP-10-E-BPA-01A, Section 2.3, Tables 2.3.1 and 2.3.2, and the WPRDS Documentation, WP-10-E-BPA-05A, Section 2.

2.1.1.2 Load-Resource Balance

RAM2010 does not perform a Federal system load-resource balance calculation for the Program Case. Instead, the model depends on the load-resource balance performed in the Loads and Resources Study, WP-10-E-BPA-01, Section 2.4. Data from the Loads and Resources Study are used to calculate the energy allocation factors (EAFs) to ensure that costs of resources are allocated to loads in the order prescribed by the Northwest Power Act. The costs of FBS resources are first allocated to the PF rate pool (consisting of COU, Federal agency, and REP loads) until FBS resources are exhausted. Exchange resources then are used to serve any remaining PF loads in the PF rate pool. DSI, New Resource, and Surplus Firm Power loads are combined into a single rate pool. Remaining REP and new resources are used to serve this combined rate pool.

2.1.1.3 Revenue Requirement

FBS costs are based on the net interest and depreciation associated with the Federal investment in the hydro projects; planned and minimum required net revenues; hydro operation and maintenance expenses; annual costs related to the Columbia Generating Station, WNP-1 and WNP-3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Trojan nuclear plant; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. REP resource costs are based on the ASCs of utilities participating in the REP, including cost adjustments if there are deeming utilities. New resource costs are those of the long-term generating contracts and renewable resources not designated as FBS replacements. Conservation costs include operating expenses, amortization, net interest and planned net revenues associated with the investment in BPA legacy conservation, conservation augmentation, and energy efficiency programs. Other BPA costs include Power Services and agency administrative and general expenses and depreciation, net interest, and planned net revenues associated with Power Services and agency investment in capital equipment. Transmission costs are the annual expenses associated with Power Services' purchase of BPA and non-Federal transmission and ancillary services.

2.1.1.4 Cost Allocation

Allocation of projected costs to rate pools is performed on an average annual energy basis in RAM2010. Generation costs for each year are allocated by the use of EAFs calculated using the results of the Loads and Resources Study, WP-10-E-BPA-01, Section 2.2. Conservation and billing credit costs, BPA's administrative and general expenses, and energy service business costs are allocated across all BPA firm loads pursuant to section 7(g) of the Northwest Power Act. The cost allocation procedures for the Program Case are the same as those used to develop BPA's proposed rates in the WPRDS, WP-10-E-BPA-05, Chapter 3.

2.1.1.5 Rate Design

The adjustments made to allocated costs in RAM2010 for the Program Case are the same as those made to develop BPA's proposed rates. These include adjustments for: (1) secondary and other revenue credits; (2) the surplus firm power revenue surplus/deficiency; (3) the section 7(c)(2) delta and margin; and (4) the DSI floor rate adjustment. These rate design adjustments are discussed below in brief. Fuller descriptions are in the WPRDS, WP-10-E-BPA-05.

Secondary and Other Revenues are earned from the sale of secondary energy that is made available by the assumption of the average of 70 water years for secondary energy generation capability. Secondary revenues are credited to loads served by FBS and new resources pursuant to Northwest Power Act section 7(g). RAM2010 uses the secondary energy sales revenue forecast produced by RiskMod, as documented in the WPRDS Documentation, WP-10-E-BPA-05A, Section 2, Table 2.5.3 for FY2010-2011, and the Risk Analysis and Mitigation Study Documentation, WP-10-E-BPA-04A, Section 1.4.1.5 for FY2012-2015.

The Surplus Firm Power Revenue Surplus/Deficiency results when available surplus firm power is sold at other than its fully allocated cost. In addition, this study assumes that long-term convertible contracts are in an exchange or power mode depending on the circumstances of the individual contracts. The WP-10 Initial Proposal assumes that all convertible contracts are in the exchange mode. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that power after adjusting for transmission costs, equals the surplus firm power revenue surplus/deficiency. The surplus/deficiency is allocated to firm loads served by FBS and new resources pursuant to Northwest Power Act section 7(g). The revenues from capacity sales are included in the surplus firm power revenue surplus/deficiency and are allocated to all firm loads served by FBS and new resources pursuant to section 7(g).

The 7(c)(2) Adjustment is made to account for the difference between the costs allocated to the DSIs and the revenues resulting from the applicable DSI rate. A net margin is used in determining the applicable DSI rate. The net margin subsumes the Value of Reserves credit and the typical margin adjustment (*see* WPRDS, Section 2.2.1). The net margin is 0.568 mills/kWh in nominal dollars. Generally, costs are reallocated, pursuant to section 7(c), from the IP rate pool to other rate pools so that the applicable DSI rate equals the applicable wholesale rate to 7(b)(2) Customers plus the net margin.

The DSI Floor Rate test ensures that the DSI rate will not be lower than the IP rate in effect for Operating Year (OY) 1985, pursuant to section 7(c)(2) of the Northwest Power Act. If the IP rate is below that floor rate, the IP rate is raised to the floor rate and an adjustment is necessary to credit additional revenues from the DSIs to other firm power customers, pursuant to section 7(c).

2.1.2 7(b)(2) Case in RAM2010

The 7(b)(2) Case section of RAM2010 calculates 7(b)(2) Case rates the same way as Program Case rates, except where the *Implementation Methodology* sets forth specific assumptions to be made that modify the Program Case.

2.1.2.1 Sales

The sales forecasts input to RAM2010 to calculate rates for the 7(b)(2) Case are the same sales forecasts used in the Program Case, with the following modifications. The 7(b)(2) Case utility sales are adjusted to exclude estimates of programmatic conservation savings, competitive acquisitions conservation, and billing credits. This upward adjustment in the utility sales forecast includes annual programmatic conservation resources that have an amortized lifetime that includes the Rate Test year of FY 2015. Programmatic conservation resources with

amortized lifetimes that end before FY 2015 are assumed to be obsolete and have been removed from the 7(b)(2)(D) resource stack and have no effect on the 7(b)(2) Case sales forecast. The 7(b)(2) Case also excludes REP loads. Sales to "Within or Adjacent" DSIs, adjusted to exclude estimates of the Conservation/Modernization program, are assumed to be transferred to the service territories of the 7(b)(2) Customers for the entire Rate Test period as 100 percent firm loads. Sales to DSIs not "Within or Adjacent" are assumed to transfer to non-7(b)(2) Customers and have no effect on the 7(b)(2) sales forecast.

2.1.2.2 Resources

The size of the FBS is identical for the Program Case and the 7(b)(2) Case. However, RAM2010 currently displays the size of the FBS in such a way that the FBS that is available to serve requirements load is shown as being slightly larger in the 7(b)(2) Case. This is because of the treatment of "other obligations" served in the Program Case that were not in existence at the time of the passage of the Northwest Power Act and are not served in the 7(b)(2) Case. If the FBS is insufficient to serve 7(b)(2) Customer loads through the test period in the 7(b)(2) Case, additional resources are assumed to come on-line. Consistent with the *2008 Implementation Methodology*, three types of additional resources can be added to serve 7(b)(2) Customer loads.

Type 1 resources are actual and planned acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case. Type 2 resources are existing resources of 7(b)(2) Customers not committed to load pursuant to section 5(b) of the Northwest Power Act. These first two types of resources include any BPA programmatic conservation and are used to serve remaining 7(b)(2) Customer load in order of least cost first. Type 3 resources are any additional needed resources priced at the average cost of resources acquired by BPA from non-7(b)(2) Customers consistent with the Program Case. These resources are brought on-line if the first two types of resources are insufficient to meet the 7(b)(2) Customer requirements in the 7(b)(2) Case. Consistent with

the *Legal Interpretation*, the portions of the Mid-Columbia hydro resources that are contracted to regional IOUs and that serve regional loads are committed to load pursuant to section 5(b) for purposes of the Rate Test. In addition, portions of the Mid-Columbia hydro resources that are contracted to regional COUs and the portion of these resources that are sold at auction are deemed to be committed to regional loads pursuant to section 5(b) unless it is demonstrated that such resources are being exported outside of the PNW.

2.1.2.3 Financing Benefits

The financing benefits analysis required by section 7(b)(2)(E)(i) of the Northwest Power Act is prepared by BPA's financial advisor, Public Financial Management. The financial advisor's financing study is contained in Appendix A to this Study. It shows that the proposed financing benefit of BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by public utilities, using 15-year term financing, is 20 basis points lower than the 7(b)(2) Case without BPA backing. For the Cowlitz Falls Project (a "Named Resource"), the proposed benefit of BPA's participation is 5 basis points between an assumed revenue bond issued with and without a BPA contract for the Project. This increases the financing costs for additional resources in the 7(b)(2) Case, thereby increasing the 7(b)(2) Case power cost of the 7(b)(2) Customers.

2.1.2.4 Load-Resource Balance

The 7(b)(2) Case section of RAM2010 adjusts the established load-resource balance from the Program Case to comport with the different loads and resource use restrictions assumed in the 7(b)(2) Case. The Program Case is in load-resource balance during the rate period. The size of the FBS, including the balancing purchase power and augmentation purchase power, is the same in the 7(b)(2) Case as in the Program Case. In addition, the Program Case assumes a small amount of new resources that are not included in the 7(b)(2) Case. The 7(b)(2) Customer loads

are larger than the Program Case PF Preference loads. In the 7(b)(2) Case, no conservation savings are assumed to have occurred, and "Within and Adjacent" DSI Loads are added to 7(b)(2) Customer loads. The larger 7(b)(2) Customer loads in the 7(b)(2) Case can result in the need to select additional resources from the 7(b)(2)(D) resource stack (*see* Appendix D).

2.1.2.5 Revenue Requirement

The revenue requirement in the 7(b)(2) Case contains the same costs as in the Program Case, with certain modifications. The 7(b)(2) Case excludes Program Case revenue requirement amounts for conservation and energy efficiency, billing credits, new resources, and the REP. The only Applicable 7(g) Costs in the Program Case revenue requirement are the amounts for conservation and energy efficiency and billing credits. By removing these costs from the initial 7(b)(2) Case revenue requirement, the Applicable 7(g) Costs have been removed from the 7(b)(2) Case. These Applicable 7(g) Costs are subtracted from the Program Case just prior to the rates for two Cases being compared. This is discussed further in Section 3.3 below. In addition, the contracts excluded from the 7(b)(2) Case (contracts not existing on the effective date of the Act) provide no revenue credits. Repayment studies are then performed for each year of the Rate Test period using the same procedures as the Program Case. The initial 7(b)(2) Case revenue requirement documentation can be found at WP-10-E-BPA-02B, Chapter 6. The 7(b)(2) Case revenue requirement includes the annual debt service amounts associated with the deferral of expensed conservation costs and the annual debt service associated with capitalized conservation costs that are chosen from the 7(b)(2) resource stack. Documentation of annual amounts (aMW) of conservation savings available to serve the 7(b)(2) Customer loads that are included in the resource stack and the related costs associated with these savings are shown in Appendix D to this study. The 7(b)(2) Case revenue requirement also includes the operating expenses and financing costs of non-conservation resources that are selected from the 7(b)(2) resource stack.

The documentation for the amount (aMW) of these non-conservation resources and their related costs is provided in Appendix C to this Study.

2.1.2.6 Cost Allocation

7(b)(2) Customers are allocated FBS and resource stack costs according to their use of the respective resources. FBS obligations are allocated costs according to their use of the FBS.

2.1.2.7 Rate Design

Rate design adjustments in the 7(b)(2) Case are performed in the same manner as in the Program Case. However, there is no 7(c)(2) delta or floor rate in the 7(b)(2) Case because there are no DSI loads. Also, the costs of the Conservation Rate Credit (CRC) are not explicitly added into the 7(b)(2) Case rates because these historical and projected costs are contained in the cost of conservation resources present in the 7(b)(2) resource stack.

3. UTILITY ASC FORECASTS FOR FY 2010-2015

To perform the Rate Test, BPA must have the ASCs for utilities participating in the REP for the rate period (FY 2010-2011) and forecasts for the following four years (FY 2012-2015). This section describes the forecasting of utility ASCs for the Rate Test.

3.1 Average System Cost Calculation

An ASC is calculated by dividing a utility's total Contract System Cost (generation and transmission costs as determined in the ASC Review Process) by its total Contract System Load (total retail load adjusted for distribution losses less New Large Single Loads). The resulting quotient is the utility's ASC. Whether a cost or load may be considered in the ASC calculation is determined pursuant to a methodology developed by BPA in consultation with regional parties. The most recent version of this methodology is the 2008 ASC Methodology (2008 ASCM). ASCs are not determined in BPA's rate cases; they are calculated in ASC Review Processes, which are separate administrative proceedings. For more information about the 2008 ASCM and the ASC Review Processes, *see* *http://www.bpa.gov/corporate/finance/ascm/*.

3.2 FY 2010-2015 ASC Calculation

3.2.1 Methodology for Forecasting ASCs

ASCs are calculated in two steps under the 2008 ASC Methodology. The ASC calculation begins with a determination of a "Base Year ASC" for the utility. The Base Year ASC is an ASC based on the data from the utility's most recent FERC Form 1 (or equivalent) at the time the utility submits its ASC filing to BPA. For this rate period, the Base Year is CY 2007. In the ASC Review Process, BPA evaluates the appropriateness of the utility's costs and loads in the Base Year ASC for conformance with the 2008 ASCM.

Once the Base Year ASC has been established, the next step is for the utility's ASC data to be adjusted for the temporal differences between the base year and the rate period. The ASC is escalated (escalation may be negative) from the utility's Base Year ASC determination to the mid-point of BPA's rate period. This escalation uses factors identified in the 2008 ASCM. The ASC that results after this final step is the utility's "Exchange Period ASC," which is referred to in this Study as the "rate period ASC." The rate period ASC changes during BPA's rate period only to reflect new resource additions or reductions that were submitted during the ASC Review Process and allowed in the utility's final ASC report.

The costs and loads used to calculate ASCs for FY 2010-2011 are then escalated for the remainder of the Rate Test period, FY 2012-2015, to forecast ASCs for the Rate Test. The discussion of ASCs in this Study focuses on the remainder of the rate test period, FY 2012-2015. However, certain background information on the determination of the rate period ASCs is provided herein for clarity. *See* http://www.bpa.gov/corporate/finance/ascm/ for additional details.

3.3 2010-2011 Rate Period ASCs

As noted in the WPRDS, Section 6.0, the rate period ASCs used in the Initial Proposal are based on the "as filed" ASCs (with certain specified adjustments) submitted by utilities participating in the ASC Review Process for FY 2010-2011. These ASC filings are currently being evaluated in the ASC Review Process. The FY 2010-2011 rate period ASCs used in the Final Proposal will be updated to conform to the final ASCs determined by BPA in the ASC Review Processes. For more information about the FY 2010-2011 ASCs, *see* WPRDS, WP-10-E-BPA-05, Section 6.0. Table 6.1 of the WPRDS summarizes the FY 2010-2011 ASCs.

3.4 ASC Forecast for FY 2012-2015

ASCs for FY 2012-2015 are forecast using a methodology that is similar to the 2008 ASCM used to determine ASCs for FY 2010-2011. First, the rate period ASCs are used as the starting point for forecasting the FY 2012-2015 ASCs. The rate period ASCs are then adjusted to include the costs of all new resources that are forecast to come on-line through the end of the rate period. Next, the rate period ASCs are escalated to the midpoint of each fiscal year through FY 2015, using the same ASC methodology and escalators that are used to determine the rate period ASCs. This escalation uses the same forecasts of inflation rates, natural gas prices, and market prices as are used to forecast BPA costs and revenues. The escalators are shown in Appendix E, Table 5, of this Study. The results of the ASC forecast for each year of the rate test period are shown in Appendix F, Tables A-H, of this Study.

The FY 2012-2015 ASC forecast assumes that all load growth is met with market purchases at utility-specific market rates. The utility-specific market rates are calculated using the individual utilities' price spreads contained in each utility's ASC filing. The Contract System Loads used in the FY 2012-2015 ASC forecast are shown in Appendix E, Table 2, of this Study.

Forecasts of ASCs for FY 2012-2015 are calculated for all utilities that filed ASCs with BPA in October of 2008. The filing utilities are Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Franklin County PUD, and Snohomish County PUD. Appendix E, Table 3, summarizes the FY 2012-2015 ASC forecasts for these utilities.

To the extent that any changes are made to the rate period ASCs as a result of BPA's final determinations in the ASC Review Process, such changes will be reflected in the WP-10 Final Proposal ASC forecasts for FY 2012-2015.

3.5 Exchange Load Forecast for FY 2012-2015

The exchange load is defined as the sum of a utility's residential and small farm loads as determined by the terms of the utility's Residential Purchase and Sales Agreement (RPSA). The forecast exchange loads are used to estimate each utility's REP benefits by comparing the utility's ASC with BPA's PF Exchange rate and then multiplying the difference by the utility's forecast exchange load.

Utilities intending to participate in the REP for FY 2010-2011 were required to submit with their ASC filings a forecast of their exchange load, measured at the retail meter, for FY 2010-2015. These exchange load forecasts are used for both the rate period (FY 2010-2011) and the remaining years of the Rate Test period (FY 2012-2015). The exchange load forecasts were increased to include distribution losses, which were calculated using the same distribution loss factors used to determine Contract System Load in the ASC filings. If distribution loss factors are changed during the ASC Review Process, the revised loss factors will be incorporated into the WP-10 Final Proposal.

Participating utilities' retail load forecasts are summarized for both the rate period, FY 2010-2011, and the remaining years of the rate test period, FY 2012-2015, in the Loads and Resources Study Documentation, WP-10-E-BPA-01A, Section 2.2, Table 2.2.8. Exchange load forecasts for FY 2012-2015 are summarized in Appendix E, Table 4, of this Study.

Appendix E, Tables 1-4, of the Study summarize each utility's Contract System Cost, Contract System Load, ASC, and Residential and Small Farm Exchange Load, respectively, for FY 2011-2015. Appendix F shows the calculations of each utility's forecast Contract System Cost, Contract System Load, and ASC. Appendix G shows additional details on the calculation of each utility's Purchase Power expense and Sales for Resale revenue.

4. SUMMARY OF RESULTS

The results for the two Cases are summarized in Tables 1 and 2 below.

4.1 Program Case

The Program Case rate for each year is based on the costs of the resources used to serve the 7(b)(2) Customers. The resource costs are then adjusted as described above and in the WPRDS, WP-10-E-BPA-05, Section 3. Table 1 below shows the projection of undiscounted nominal Program Case rates.

4.2 7(b)(2) Case

The annual amount to be paid by 7(b)(2) Customers for their power needs in the 7(b)(2) Case is based on the cost of FBS resources and the cost of additional resources from the 7(b)(2)(D) resource stack. These power costs include adjustments for reserves and financing, *i.e.*, the absence of the reserve benefits and financing benefits implicit in the cost of power in the Program Case. The power costs are then subject to the same cost and revenue adjustment allocations as the Program Case rates. Table 2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

4.3 The Section 7(b)(2) Rate Test

RAM2010 performs the Rate Test after it calculates the two sets of test period rates. First, the projected Program Case rates are reduced by the applicable 7(g) costs allocated to the rates for each year. The applicable 7(g) costs are described in section 7(b)(2) as "conservation, resource and conservation credits, experimental resources and uncontrollable events." The applicable 7(g) costs quantified for the Rate Test are comprised of BPA's acquired and projected conservation, energy efficiency, and CRC costs, and the cost of billing credits. As outlined

above in Section 2.1.2.5, applicable 7(g) costs were removed from the 7(b)(2) Case revenue requirement. If there were uncontrollable event costs present in the Program Case revenue requirement, they also would have been excluded from the 7(b)(2) Case revenue requirement. Because these costs are excluded/subtracted from the 7(b)(2) Case at its inception by excluding them from the revenue requirement, there is no need to subtract them at this point in performing the Rate Test. This explains why Table 2, 7(b)(2) Case Rates, does not have an amount of 7(g) costs to be subtracted. The projected rates for each year then are discounted to the beginning of FY 2010 using factors based on BPA's projected borrowing rate for each year. Table 3 shows BPA's forecast borrowing rates that were used in the discounting procedure and the corresponding cumulative discount factors. When applied to the rates in the two Cases, the simple average of the discounted rates over the Rate Test period is calculated, rounded to two decimal places, and compared. As shown in Table 4, the Rate Test triggers by 8.07 mills/kWh. Therefore, an adjustment to the WP-10 proposed PF Preference rate, valued at about $1,029 million, (*see* WPRDS documentation, Section 2, Table 2.5.9) is required.

Table 1
Program Case Rates

(Nominal mills/kWh)

A	B	C	D
Fiscal Year	Rate	Applicable 7(g) Costs	Net Rate
2010	36.45	1.59	34.86
2011	37.06	1.54	35.52
2012	36.27	1.44	34.83
2013	38.15	1.48	36.67
2014	38.07	1.45	36.62
2015	40.07	1.37	38.70

Table 2
7(b)(2) Case Rates

(Nominal mills/kWh)

A	B
Fiscal Year	7(b)(2) Rate
2010	25.97
2011	26.36
2012	23.55
2013	26.44
2014	26.10
2015	27.82

Table 3
Discount Factors for the Rate Test

A	B	C
Fiscal Year	Annual BPA Borrowing Rate[1]	Cumulative Discount Factor[2]
2010	.0679	.9364
2011	.0693	.8757
2012	.0669	.8202
2013	.0669	.7693
2014	.0669	.7211
2015	.0669	.6759

[1] Revenue Requirement Study Documentation, WP-10-E-BPA-02B, Chapter 6.
[2] $DiscFact_t = DiscFact_{t-1}/(1 + BorrowRate_t)$; Fiscal Year 2009 equals 1.

Table 4
Comparison of Rates for Test
(Discounted mills/kWh)

A	B	C
Fiscal Year	Discounted Program Case Rate	Discounted 7(b)(2) Case Rate
2010	32.64	24.32
2011	31.10	23.08
2012	28.59	19.33
2013	28.21	20.34
2014	26.41	18.82
2015	26.16	18.80
Average Rate	28.85	20.78

Difference of Average Rates 8.07 mills/kWh

Section 7(b)(2)
LEGAL INTERPRETATION

Attachment 1
to
Section 7(b)(2) Rate Test Study

WP-10-E-BPA-06
Wholesale Power Rate Initial Proposal
2010 BPA Rate Case

SECTION 7(b)(2) OF THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

LEGAL INTERPRETATION

September 2008

WP-07-A-06

DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act

I. Background

A. Relevant Statutory Provisions

The Administrator of the Bonneville Power Administration (BPA) is charged with the responsibility of implementing section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §§ 839, *et seq*. An agency's interpretation of the statute it is charged to administer is entitled to great deference; in particular, the United States Supreme Court has held that "it is clear that the Administrator's interpretation of the Regional [Northwest Power] Act is to be given great weight." *Aluminum Co. of America v. Central Lincoln Peoples' Util. Dist.*, 467 U.S. 380, 389 (1984).

Basic principles of statutory construction must be followed in interpreting the Northwest Power Act. These principles require that particular provisions of a statute be interpreted to give effect to its overall purposes. *United States v. Am. Trucking Ass'n*, 310 U.S. 534, 543 (1950). Wherever possible, statutory provisions should be construed so as to be consistent with each other. *Adams v. Howerton*, 673 F.2d 1036, 1040 (9th Cir. 1982), *cert. denied*, 458 U.S. 1111 (1982). Thus, BPA interprets the Northwest Power Act in a manner which seeks consistency among the requirements of each section of the Northwest Power Act.

In addition to the Northwest Power Act, BPA is responsible for establishing rates pursuant to the Bonneville Project Act. 16 U.S.C. § 832, *et seq.*, the Federal Columbia River Transmission System Act, 16 U.S.C. § 838, *et seq.*, and the Flood Control Act of 1944, 16 U.S.C. § 825, *et seq.* These statutes require BPA to set rates, in accordance with sound business principles, at levels sufficient to recover BPA's total system costs, including repayment of the Federal Treasury investment in the Federal Columbia River Power and Transmission System over a reasonable number of years. All statutory provisions concerning the timely recovery of BPA's revenue requirement are relevant to the interpretation of the Northwest Power Act. For "[w]hen there are two acts upon the same subject, the rule is to give effect to both if possible." *Morton v. Mancari*, 417 U.S. 535, 551 (1974), *quoting United States v. Borden Co.*, 308 U.S. 188, 198 (1939).

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, contains a number of directives that the BPA Administrator must consider in establishing rates for the sale of electric energy and capacity and for the transmission of non-Federal power. Section 7(b)(2), commonly referred to as the "rate test," is one of these directives. Section 7(b)(2) of the Northwest Power Act, 16 U.S.C. § 839e(b)(2), provides:

After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative, and Federal agency customers exclusive of amounts charged such customers under subsection 7(g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if, the Administrator assumes that –

(A) the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are

(i) served by the Administrator, and

(ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives;

(B) public body, cooperative, and federal agency customers were served, during such five-year period, with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980, (during the remaining term of such contracts) excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph;

(C) no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period;

(D) all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –

(i) purchased from such customers by the Administrator pursuant to section 6, or

(ii) not committed to load pursuant to section 5(b),

and were the least expensive resources owned or purchased by public bodies or cooperatives; and any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator; and

(E) the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from –

(i) reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, and

(ii) reserve benefits as a result of the Administrator's actions under this Act

were not achieved.

16 U.S.C. § 839e(b)(2).

B. Scope of Interpretation

This Legal Interpretation resolves only the basic legal issues necessary to implement section 7(b)(2) and modifies the first Legal Interpretation issued June 8, 1984. *See* Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act, 49 Fed. Reg. 23,998 (June 8, 1984).

II. Interpretation

A. Definitions

This section contains definitions applicable to section 7(b)(2). Terms identified in the Northwest Power Act have the same meaning in this interpretation, unless further defined.

1. <u>Relevant Rate Case</u>: The section 7(i) wholesale power rate adjustment proceeding being conducted at the time the projections for section 7(b)(2) are made, and in which any adjustment to rates in accordance with section 7(b)(2) may be reflected.

2. <u>General Requirements</u>: The public body, cooperative, and Federal agency customers' electric power assumed in the Relevant Rate Case to be purchased from BPA, exclusive of new large single loads. General Requirements are limited to power purchased from BPA under section 5(b) of the Northwest Power Act; section 5(c) purchases from BPA are not included.

3. <u>7(b)(2) Customers</u>: Those firm power customers of BPA that are listed in section 7(b)(2) of the Northwest Power Act as subject to the rate test, *viz.*, public bodies, cooperatives, and Federal agencies.

4. <u>Applicable 7(g) Costs</u>: The costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), *viz.*, costs chargeable to 7(b)(2) Customers for

conservation, resource and conservation credits, Experimental Resources, and Uncontrollable Events.

5. Uncontrollable Event: A discrete event which differs from the continuum of changing events that occur in nature, business, and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

6. Experimental Resources: Resources that are undergoing research and development and are funded by BPA in full or in part.

7. Five-Year Period: The rate recovery period of the Relevant Rate Case, plus the ensuing four years. If the Relevant Rate Case has more than a one-year rate recovery period, the Five-Year Period will be greater than five years.

8. Program Case: The entire process of calculating rates to be charged in the Five-Year Period of the Relevant Rate Case under the provisions of the Northwest Power Act other than section 7(b)(2), including all specific data, assumptions, and results.

9. 7(b)(2) Case: The entire process of calculating rates for the relevant Five-Year Period under the provisions of section 7(b)(2) of the Northwest Power Act, including all specific data, assumptions, and results.

10. Five Assumptions: The five differences between the Program Case and the 7(b)(2) Case specified in subsections (A) through (E) of section 7(b)(2) of the Northwest Power Act.

11. DSI Loads: Those loads of direct service industries (DSIs) that are forecast to be served by BPA, during the Five-Year Period, pursuant to section 5(d)(1) or 5(f) of the Northwest Power Act.

12. Within or Adjacent: Relating to DSI customer loads determined in accordance with section 7(b)(2)(A) to be electrically within or adjacent to the geographic service territories of 7(b)(2) Customers.

13. Quantifiable Monetary Savings: The change in annual costs attributable to differences in resource financing or Reserve Benefits.

14. Reserve Benefits: The annual financial value of (1) resources designated by BPA as providing reserves, or (2) interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to start up and serve load during unexpected conditions.

B. General Approach and Specific Issues of Interpreting Section 7(b)(2)

Section 7(b)(2) assures that 7(b)(2) Customers are charged no more for their General Requirements after July 1, 1985, than they would have been charged if the Five Assumptions were to be realized. These assumptions direct BPA to hypothesize power supply arrangements between itself and its customers that are quite different from reality. Implementation of the Five Assumptions listed in section 7(b)(2) is by nature an exercise in speculation. This interpretation was undertaken to reduce this inherent speculation insofar as possible.

1. Interpretation: Section 7(b)(2) limits the 7(b)(2) Case to the Five Assumptions listed in section 7(b)(2) and the secondary effects of those assumptions.

Discussion:

The Northwest Power Act provides that after July 1, 1985, the 7(b)(2) Customers' power costs "may not exceed … as determined by the Administrator" the power costs for General Requirements based on the enumerated Five Assumptions. 16 U.S.C. § 839e(b)(2). This language grants the Administrator discretion to determine the manner in which the Five Assumptions of section 7(b)(2) are applied and the rate test is implemented. However, BPA recognizes that the reasonableness of methodologies used to implement section 7(b)(2) will be tested in the Relevant Rate Case.

The Administrator will exercise his discretionary authority in the following manner. Except for the Five Assumptions specified in section 7(b)(2), all underlying premises will remain constant between the Program Case and the 7(b)(2) Case. Assumptions not specified by the statute will not be considered. Secondary effects, however, of the Five Assumptions will be given full recognition in the modeling of the 7(b)(2) Customers' power costs in the 7(b)(2) Case. This general approach will allow the 7(b)(2) Case to be modeled under the same accepted ratemaking techniques used in the Program Case. This approach will also avoid the modeling of a hypothetical world that attempts to reflect in extreme detail what would have occurred had the Northwest Power Act not been enacted.

The legislative history of the Northwest Power Act supports limiting the assumptions of the 7(b)(2) Case to those specified in the statute. The House Committee on Interstate and Foreign Commerce Report accompanying S. 885 (the bill that became the Northwest Power Act) notes that "[t]he assumptions to be made by the Administrator in establishing this ceiling are specifically set forth." H. Rep. No. 976-I, 96th Cong., 2d Sess. 68 (1980). Similarly, the Report of the House Committee on Interior and Insular Affairs declares that "[s]ubsection 7(b)(2) establishes a 'rate ceiling' for BPA's preference customers, and specifies the method of calculating this ceiling…" H. Rep. No. 976-II, 96th Cong., 2d Sess. 52 (1980).

Legislative history also supports including the unavoidable secondary effects of the assumptions listed in the Northwest Power Act. In particular, in addressing Reserve Benefits,

Appendix B to the Report of the Senate Committee on Energy and Natural Resources provides that in addition to costs specifically described in sections 7(b)(2)(B) and (D), the Administrator is to consider "[a]ny other general system operating costs, including reserves…" S. Rep. No. 272, 96th Cong., 1st Sess. (1979), Appendix B, at 58.

As an illustration of the secondary effects referred to above, BPA identified two secondary effects of the Five Assumptions found in section 7(b)(2) in its 1984 Legal Interpretation that continue to be relevant. These effects involve surplus levels and secondary energy markets. The secondary effects must be included in section 7(b)(2) methodologies as natural consequences of the Five Assumptions in section 7(b)(2) on the results of underlying premises that are held constant between the Program Case and the 7(b)(2) Case. Surplus levels and the secondary energy market must change as a natural consequence of the Five Assumptions. As the DSIs are assumed to shift to the private utilities and 7(b)(2) Customers under section 7(b)(2), BPA's load/resource balance changes. This change will affect the level of BPA's surplus. The secondary energy market will also change; the top quartile of DSI Loads will not be served by BPA's secondary energy. Any additional secondary effects will be identified by BPA in the relevant rate case.

Section 7(b)(2) requires BPA to assume that the 7(b)(2) Case is identical to the Program Case except for those differences required by the Five Assumptions set out in section 7(b)(2) (A)-(E) and the secondary effects. Present modeling techniques used in the Program Case, which will be used in the modeling of the 7(b)(2) Case, incorporate secondary effects.

2. Interpretation: Implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).

Discussion:

BPA will conscientiously follow the requirements of section 7(b)(2) to perform the "rate test" for its public body, cooperative, and Federal agency customers. If the results of the rate test indicate that BPA must recover costs in excess of those allowed under section 7(b)(2), BPA will implement the section 7(b)(3) supplemental rate charge provision for that purpose. BPA's concern is that failure to recover some, or all, of the reallocated costs "through supplemental rate charges for all other power sold by the Administrator to all customers" may result in BPA's inability to meet the requirements of section 7(a). Such a determination, if it occurs, would be rigorously documented and exposed to careful review during the section 7(i) process for the Relevant Rate Case. Should this occur, BPA would be forced to resolve a possible conflict among sections 7(b)(2), 7(b)(3), and 7(a).

Section 7(a) of the Northwest Power Act requires that BPA rates recover the costs of the electric power and transmission systems, including the repayment of Federal Treasury investments in those systems. Section 7(a) reaffirms this longstanding obligation which was articulated earlier in the Bonneville Project Act and the Federal Columbia River Transmission

System Act. Section 7(b)(2) must be applied in a manner which enables BPA to set rates at levels sufficient to recover costs, or the rates will not receive confirmation and approval from the Federal Energy Regulatory Commission. *See* 16 U.S.C. § 839e(a)(2).

The legislative history of the Northwest Power Act supports application of section 7(b)(2) in a manner consistent with BPA's primary statutory obligation that its rates recover costs. The House Interior Committee report declares that:

> Section 7 of the legislation sets out the requirements BPA must follow when fixing rates for the power sold its customers under this legislation. Subject to the general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs, BPA is required by the legislation to establish the following rates: [report continues by setting out rate structure of the Act].

H. Rep. No. 976-11, 96th Cong., 2d Sess. 36 (1980).

Section 7(a)(2) illustrates the importance of BPA's statutory obligation to set rates at levels sufficient to collect its costs. Section 7(a)(2) states that FERC cannot approve BPA's rates unless the rates "are sufficient to assure repayment of federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs," 16 U.S.C. § 839e(a)(2)(A), and "are based upon the Administrator's total system costs …" 16 U.S.C. § 839e(a)(2)(B). Indeed:

> BPA is a self-financed agency under the terms of the Federal Columbia River Transmission System Act of 1974. This means that BPA receives no appropriations. It is required by law to cover its full costs through its own revenues derived from the sale of power and other services. … The United States of America does not stand behind BPA's obligations. … BPA alone must meet these obligations, and BPA's rates cannot be approved by FERC unless they are sufficient to meet these obligations.

126 Cong. Rec. H9843 (daily ed. Sep. 29, 1980) (statement of Rep. Ullman).

BPA is neither predetermining the results of the rate test nor suggesting a disregard for section 7(b)(2) with this discussion. BPA is not suggesting a solution to any problem arising from a potential conflict among sections 7(a), 7(b)(2), and 7(b)(3). BPA is merely attempting through this interpretation to alert its customers and the public to one possible problem which may present itself in the future.

3. Interpretation: Applicable 7(g) Costs are to be excluded from the Program Case rates and the 7(b)(2) Case rates prior to comparison with the 7(b)(2) Case rates.

Discussion:

Section 7(b)(2) states: "… the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total … an amount equal to the power costs for general requirements of such customers if, the Administrator assumes …" the Five Assumptions. 16 U.S.C. § 839e(b)(2).

The foregoing language describes the basic comparison of the Program Case and the 7(b)(2) Case in performing the section 7(b)(2) rate test. In particular, it sets forth the instructions on how BPA is to initially construct the two revenue requirements that will serve as the foundation of the rate test comparison. The language begins with the Program Case. The revenue requirement in the Program Case rate is to be constructed from the "projected amounts to be charged for firm power" for the "general requirements" of BPA's preference customers. This phrase refers to the firm power costs BPA is proposing to recover through its 7(b) rates. Thus, BPA is to start with its total revenue requirement in the Program Case.

The statutory language further directs BPA to modify this revenue requirement by excluding "the amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events …" In other words, BPA must subtract the identified 7(g) costs (referred to hereafter as Applicable 7(g) Costs) from the Program Case revenue requirement. This reduces the revenue requirement in the Program Case, resulting in the power costs to be recovered in the Program Case.

The second half of the above-noted language then describes how BPA is to initially construct the revenue requirement in the 7(b)(2) Case. Specifically, the 7(b)(2) Case revenue requirement is equal to "the power costs for general requirements of such customers …" as modified by the Five Assumptions. The phrase "power costs for general requirements of such customers" is a direct reference back to the "projected amounts to be charged" when calculating the costs of the Program Case. Because the two clauses are identical in all material respects, the same power costs that were used to serve the "general requirements" in the Program Case should be used as the starting point to construct the revenue requirement for the 7(b)(2) Case; that is, "the projected amounts to be charged for firm power, subject to the Five Assumptions and their secondary effects."

This interpretation, in addition to being consistent with the aforementioned statutory text, also makes practical sense when actually implementing the 7(b)(2) rate test. First, having symmetry between the initial revenue requirements in the Program Case and the 7(b)(2) Case ensures that the later application of the Five Assumptions and their secondary effects is the

central reason the rate test triggers or fails to trigger. Congress specifically identified the Five Assumptions as the factors the Administrator was to "assume" in determining the power costs in the 7(b)(2) Case. By limiting the cost differences between the Program Case and the 7(b)(2) Case before the application of these assumptions, BPA can give the full and proper effect to the rate test construct envisioned by Congress. Without this symmetry, the rate test results may become skewed by factors other than the Five Assumptions and their secondary effects. For example, if Applicable 7(g) Costs were excluded from the Program Case (making it less expensive), but included in the 7(b)(2) Case (making it more expensive), it could create a cost incongruity that could become a determinative factor in whether the rate test will trigger. Having an equilibrium between the costs in the Program Case and the 7(b)(2) Case reduces these unintended consequences and preserves the Congressionally identified drivers of the rate test – the Five Assumptions and their secondary effects.

Second, this interpretation also avoids potential conflicts with the remaining sections of the 7(b)(2) rate test. Specifically, if the "power costs" used in the 7(b)(2) Case were not interpreted to mean the same power costs in the Program Case, exclusive of costs related to the Five Assumptions and their secondary effects, a conflict would occur between the above-mentioned paragraph and section 7(b)(2)(D)(i), the fourth of the Five Assumptions. The fourth assumption specifies that any remaining General Requirements in the 7(b)(2) Case that have not been satisfied by Federal Base System (FBS) resources pursuant to the second assumption (*i.e.*, section 7(b)(2)(B)) are met with resources taken from a resource stack developed in accordance with subsection 7(b)(2)(D). *See* Issue 11, *infra*.

Section 7(b)(2)(D) provides that, in conducting the 7(b)(2) test, the Administrator is to assume that:

> all resources that would have been required, during such five-year period, to meet remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subparagraph (B) of this paragraph) were –
>
> (i) purchased from such customers by the Administrator pursuant to section 6, or
>
> (ii) not committed to load pursuant to section 5(b),
>
> and were the least expensive resources owned or purchased by public bodies and cooperatives; and any additional needed resources were obtained at the average cost of all other resources acquired by the Administrator…

16 U.S.C. § 839e(b)(2)(D). Resources that meet the criteria identified in section 7(b)(2)(D) are assumed to be in a "resource stack," available for use to serve the General Requirements of the 7(b)(2) Customers in the 7(b)(2) Case. This resource stack includes three types of resources. Type 1 resources are resources the Administrator acquired or plans to acquire from 7(b)(2) Customers pursuant to section 6 of the Northwest Power Act. Type 2 resources are not committed to load pursuant to section 5(b). Type 3 resources are any remaining needed

resources. *See* Issue 11, *infra*. It is the Type 1 resources that create an anomaly in the treatment of 7(g) costs.

When resources are included in the resource stack, they are not used to serve General Requirements in the 7(b)(2) Case unless needed and selected from the stack. Section 7(b)(2)(D) refers to "resources … purchased from such [7(b)(2)] customers by the Administrator pursuant to section 6 [of the Northwest Power Act]." *Id.* Conservation is a resource that is assumed to be available in the resource stack. The Northwest Power Act specifically defines conservation as a resource:

> "Resource" means – electric power, including the actual or planned electric power capability of generating facilities, or actual or planned *load reduction resulting from* direct application of a renewable energy resource by a consumer, or from *a conservation measure*.

16 U.S.C. § 839a(19) (emphasis added). Furthermore, conservation is acquired pursuant to section 6 of the Act. Section 6 provides, *inter alia*, that "[t]he Administrator shall acquire such resources through conservation …" 16 U.S.C. § 839d(a)(1). The term "such resources" refers to resources sufficient to meet the Administrator's contractual obligations under section 5 to provide electric power to meet firm power loads. Therefore, conservation is a Type 1 resource and must be included in the resource stack.

Conservation resources and billing credit resources, however, can only be included in the resource stack if Applicable 7(g) Costs are removed from the starting 7(b)(2) Case revenue requirements. Recall that the Applicable 7(g) Costs exclude the cost "*of conservation, resource and conservation credits,* experimental resources and uncontrollable events …" 16 U.S.C. § 839e(b)(2) (emphasis added). The import of leaving the Applicable 7(g) Costs in the 7(b)(2) Case is that the costs of "conservation, resource and conservation credits" will remain in the 7(b)(2) revenue requirement. With conservation costs already in the costs of the 7(b)(2) Case, there is no logical way for conservation resources to be available *again* in the resource stack. To do so would be to effectively double-count the conservation costs – first in the 7(b)(2) revenue requirement (because they were never taken out), and second as the costs of a Type 1 resource (assuming it is selected).   The only way to avoid this double-counting is to either remove the conservation costs from the 7(b)(2) Case revenue requirement *or* remove conservation resource costs from the resource stack.

In BPA's view, the more appropriate alternative is the former. Treating conservation as a Type 1 resource gives full effect to section 7(b)(2)(D)(i). The Administrator will be fulfilling the Congressional mandate to include resources in the 7(b)(2) Case resource stack "purchased from such customers by the Administrator pursuant to section 6 …"; *e.g.*, conservation resources. 16 U.S.C. § 839e(b)(2)(D)(i). By contrast, the latter alternative of removing all conservation costs from the resource stack would completely frustrate the purpose of referring to section 6 resources in section 7(b)(2)(D)(i). This is also consistent with the lack of "exclusive of" language after the reference in section 7(b)(2) to "power costs for general requirements of such

customers …" The better interpretation is therefore to include conservation as a Type 1 resource. To effectuate this interpretation, Applicable 7(g) Costs, which include conservation costs, must be removed from the 7(b)(2) Case revenue requirement.

In summary, BPA will interpret the aforementioned statutory language as meaning that the Program Case and 7(b)(2) Case must begin with the same power costs, exclusive of costs related to the Five Assumptions and their secondary effects. That is, the costs of resources associated with the Applicable 7(g) Costs will be excluded from the 7(b)(2) Case power costs through application of the Five Assumptions. The Applicable 7(g) Costs will be excluded from the Program Case rates prior to comparison with the 7(b)(2) Case rates. This interpretation is consistent with the statutory language and the purpose of the section 7(b)(2) rate test. It also avoids unnecessary conflicts with, and gives full effect to, the other provisions of section 7(b)(2).

4. Interpretation: The appropriate Five-Year Period is the rate recovery period for the applicable rate case plus the ensuing four years.

Discussion:

Section 7(b)(2) states: "… during any year after July 1, 1985, plus the ensuing four years, …" and several times thereafter "… during such five-year period …" "Any year," in this context, refers to the period of time applicable to the opening statement of section 7(b)(2); namely, the period over which "the projected amounts to be charged for firm power" are applicable, otherwise known as the revenue recovery period.

BPA has had varying lengths of revenue recovery periods in the 22 years between July 1, 1985, and October 1, 2007. Four times BPA has used two-year periods, twice BPA has used five-year periods, once for one year, once for three years, and once for 27 months. In each of these periods, the rate test was performed on the basis that the revenue recovery period was the "first year" of the Five-Year Period. For each of these rate tests, the four years subsequent to the last year of the revenue recovery period were appended to form the Five-Year Period.

It is reasonable to consider that the Five-Year Period might encompass more than 60 months. As noted above, the rate test is to compare the projected amounts to be charged for firm power. In the instance of a revenue recovery period that encompasses more than 12 months, the projected amounts to be charged are developed for the entire revenue recovery period. Therefore, to be consistent with the development of the amounts to be charged, it is reasonable to consider that time period, be it 12 months or more, the first year of the period of consideration for the rate test.

5. Interpretation: 7(b)(2) Customers' loads include DSI Loads that are Within or Adjacent to the 7(b)(2) Customers' service territories.

Discussion:

Section 7(b)(2)(A) provides that BPA is to assume that "the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customer loads which are: (i) served by the Administrator, and (ii) located within or adjacent to the geographic service boundaries of such public bodies and cooperatives …" 16 U.S.C. § 839e(b)(2)(A). The plain language of section 7(b)(2)(A) requires the Administrator to assume that 7(b)(2) Customers' loads include any Within or Adjacent DSI Loads during the Five-Year Period.

The legislative history of the Northwest Power Act also supports BPA's interpretation of the statute. In the analysis of the section 7(b)(2) directives contained in Appendix B to the Senate Report, S. Rep. No. 272, 96th Cong., 1st Sess., at 65-79 (1979), forecast DSI Loads were transferred from BPA to 7(b)(2) Customers for the entire test period regardless of contracts in effect as of the effective date of the Northwest Power Act. In the projections contained in Appendix B, calculations of public agency loads for the 7(b)(2) Case included a full 85 percent of projected DSI Loads beginning in 1980 (85 percent was the amount determined to be "Within or Adjacent" to preference agency service areas). Although Appendix B is not conclusive evidence of legislative intent, it was "an important part of the common understanding about how the costs of resources would be distributed as a result of [the Northwest Power Act]." *Id.* at 31. Appendix B is a useful tool for statutory construction where it speaks directly to an issue and does not conflict with the language of the statute.

6. Interpretation: BPA will use Appendix B of the Senate Report to assist in determining which DSI Loads are Within or Adjacent to the geographic service boundaries of 7(b)(2) Customers.

Discussion:

Section 7(b)(2)(A) requires the Administrator to assume that during the relevant Five-Year Period, "the public body and cooperative customers' general requirements had included … the direct service industrial customer loads which are … located within or adjacent to the geographic service boundaries of such public bodies and cooperatives …" 16 U.S.C. § 839e(b)(2)(A). It is not apparent from the statute how BPA is to resolve the question of which DSIs are Within or Adjacent to public body and cooperative customers' boundaries. Therefore, BPA must look to legislative history to resolve the ambiguity.

The legislative history of the Northwest Power Act indicates that a determination of which DSIs are Within or Adjacent to public body and cooperative customers' boundaries was made in Appendix B. S. Rep. No. 272, 96th Cong., 1st Sess., Appendix B, at 66. Appendix B includes a

table listing the DSIs "within BPA preference customers' service areas," DSIs "adjacent to BPA preference customers' service areas," and those DSIs that "could not readily be served by BPA preference customers." *Id.*

The Within or Adjacent table in the numerical analysis in Appendix B is accompanied by a narrative explanation which states that the loads for establishing resource requirements under section 7(b)(2) will include "DSI total loads within or adjacent to the service territory of the public bodies and cooperatives. (85 percent of existing DSIs as shown in the attached table)." *Id.* at 58. The clear and detailed nature of the Within or Adjacent table and the narrative explanation in Appendix B convince BPA that Congress intended the Appendix B table to be used in resolving which DSIs are Within or Adjacent to the service territories of public body and cooperative customers. The Appendix B table will be disregarded only if conditions of service to those DSI customers change, such as in the case of termination of BPA service to a DSI industrial plant, or if the location of the DSI changes from an IOU service territory to a public utility service territory.

Adjacent will be assessed on electrical connections rather than a strictly locational basis. Circumstances may occur where a DSI's location may be outside of a 7(b)(2) Customer's service territory, but a direct electrical connection exists between the DSI and the 7(b)(2) Customer. Conversely, a DSI's location may be inside a 7(b)(2) Customer's service territory, but no direct electrical connection exists between the DSI and the 7(b)(2) Customer. This determination will consider normal operating electrical connections and disregard emergency connections.

7. Interpretation: All DSI Loads assumed to be placed on 7(b)(2) Customers will be treated as firm loads.

Discussion:

Section 7(b)(2)(A) provides that BPA is to assume "that the public body and cooperative customers' general requirements had included during such five-year period the direct service industrial customers loads …" 16 U.S.C. § 839e(b)(2)(A). Section 7(b)(2)(A) does not expressly state the nature or quality of service assumed to be provided by the public bodies and cooperatives to the relevant DSI Loads.

The DSI Loads originally served by BPA under the Northwest Power Act included three quartiles that were firm loads and one quartile (the first quartile) that BPA did not plan or acquire resources to serve. However, the language of the Act is compelling that Congress intended all relevant DSI Loads, assumed to be served by public bodies and cooperatives, to be treated as firm.

Section 7(b)(2)(A) requires BPA to assume that the loads of relevant DSIs are included in the 7(b)(2) Customers' "general requirements," a term defined by section 7(b)(4) of the Northwest Power Act as limited to electric power purchased from the Administrator under

section 5(b) of the Act. Section 5(b) deals exclusively with firm power. In addition, section 7(b)(2)(B) requires the Administrator to assume that public body, cooperative, and Federal agency customers are served first with the FBS resources, and section 7(b)(2)(D) requires that additional resources be assumed to serve the remaining general requirements of the 7(b)(2) Customers.

The legislative history of the Northwest Power Act supports interpreting the statute to require 7(b)(2) Customers' firm power General Requirements in the 7(b)(2) Case to include all DSI Loads served by the Administrator. This includes DSI Loads that BPA does not plan or acquire resources to serve (*e.g.*, first-quartile service) in the Program Case. In Appendix B, all four quartiles of DSI Loads were treated as firm when assigned to public agency customers in the 7(b)(2) Case.

8. Interpretation: Section 7(b)(2)(B) necessitates an examination of Program Case contracts in the determination of "Federal base system resources not obligated to other entities."

Discussion:

Section 7(b)(2)(B) provides that the Administrator is to assume that 7(b)(2) Customers were served by FBS resources "not obligated to other entities under contracts existing as of December 5, 1980 (during the remaining term of such contracts), excluding obligations to direct service industrial customer loads included in [Section 7(b)(2)(A)])." 16 U.S.C. § 839e(b)(2)(A). Unlike the assumption relating to DSI Loads served by public body and cooperative customers, section 7(b)(2)(B) requires BPA to make two factual determinations: (1) what the level of FBS resources is, and (2) what level of FBS resources is obligated for service to other entities, for all or a portion of the relevant Five-Year Period. The first determination is necessary because the FBS includes resources purchased by BPA under long-term contracts. Expiration of these contracts may cause a change in the size of the FBS during the relevant Five-Year Period.

The second determination concerns BPA power sales contracts or other obligations existing as of the effective date of the Northwest Power Act. Should these contractual obligations on FBS resources be removed through expiration of the relevant contracts, the size of FBS resources available to 7(b)(2) Customers would increase. Obligations on FBS resources include uses of power mandated by treaty, statute, or contracts entered into by BPA before December 5, 1980. The DSI obligations referenced in subsection 7(b)(2)(B) have since expired, rendering the "excluding obligations" language no longer effective.

Any contract that BPA enters into subsequent to December 5, 1980, that exchanges FBS capacity for energy, exchanges seasonal FBS energy, or for the sale of FBS capacity with the return of the energy, will be assumed only if there is FBS surplus to 7(b)(2) Customer needs. Therefore, the energy and revenue from such contracts will not be recognized in the 7(b)(2) Case unless, and to the extent that, there is surplus FBS in the 7(b)(2) Case.

9. Interpretation: Section 7(b)(2)(B) requires the allocation of resource pools to load pools in the Program Case to be reconsidered in the 7(b)(2) Case.

Discussion:

Section 7(b)(2)(B) states that the Administrator is to assume that "public body … customers were served … with Federal base system resources not obligated to other entities under contracts existing as of December 5, 1980 … excluding obligations to direct service industrial customer loads included in subparagraph (A) of this paragraph." 16 U.S.C. § 839e(b)(2)(B).

In the Program Case, section 7(b)(1) sets forth the sequence of allocating resource pools to load pools.

> Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources.

The resource cost allocation hierarchy established by section 7(b)(1), and complemented for other rates in sections 7(c)(1)(A) and 7(f), is that the FBS is to be used first to serve 7(b) loads, then for 7(c) loads and 7(f) loads until the FBS resources are exhausted. After the FBS resources are exhausted, BPA uses power acquired from the section 5(c) exchange to serve remaining loads. After using FBS and exchange resources, other resources acquired by BPA, also referred to as new resources, are used to serve remaining loads.

The Program Case uses this resource cost allocation hierarchy to apply the resource pools, and their costs, to the load pools as the method of assigning resource costs to the load pools. However, in the 7(b)(2) Case, the size of the load pools will be different than in the Program Case. For example, section 5(c) exchange loads are removed from the 7(b)(2) Case load pool, thereby creating a smaller 7(b) load pool in the 7(b)(2) Case.

As a result of the different sizes of load pools in the two cases, the 7(b)(2) Case must construct its own separate allocation of resource pools to load pools. Furthermore, because of the explicit exclusion of the section 5(c) exchange in the 7(b)(2) Case, the exchange resource pool is eliminated. Lastly, because additional resources necessary in the 7(b)(2) Case are to be added through the 7(b)(2)(D) resource stack, the new resource resource pool is eliminated from the 7(b)(2) Case. All of these differences will result in different resource cost allocations than in the Program Case.

10. Interpretation: Section 7(b)(2)(C) requires the exclusion of all costs relating to the section 5(c) exchange, otherwise known as the Residential Exchange Program, from the 7(b)(2) Case. In addition, the loads and resources associated with the exchange will also be excluded from the 7(b)(2) Case.

Discussion:

Section 7(b)(2)(C) states that the Administrator is to assume that "no purchases or sales by the Administrator as provided in section 5(c) were made during such five-year period." 16 U.S.C. § 839e(b)(2)(C). This language unmistakably provides that the 7(b)(2) Case is to assume that the Residential Exchange Program is to be excluded from consideration. This includes all aspects of the exchange: the costs, the purchases, and the sales. Further, any implementation costs included in the Program Case should be excluded from the 7(b)(2) Case, as should any costs associated with a settlement of residential exchange benefits.

11. Interpretation: Section 7(b)(2)(D) identifies three additional resource types assumed to be available to meet the 7(b)(2) Customers' Remaining General Requirements when FBS resources are exhausted. Type 1 are those resources not included in the FBS that are actually acquired by BPA from 7(b)(2) Customers in the Program Case. Type 2 are those resources owned or purchased by the 7(b)(2) Customers and not dedicated to load by public agencies or investor-owned utilities pursuant to section 5(b). These two types of resources are to be stacked in order of cost and then pulled from the stack to meet 7(b)(2) Customers' loads as needed, least expensive first. Type 3 resources are additional acquired resources not included in the FBS, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the Five-Year Period.

Discussion:

Section 7(b)(2)(D) describes the manner in which additional resources are assumed to be acquired to meet the 7(b)(2) Customers' loads when FBS resources are exhausted. Three types of additional resources are available in the 7(b)(2) Case. The first type of resource is described in section 7(b)(2)(D)(i) as being resources that were "purchased from such customers by the Administrator pursuant to section 6." These are the resources actually acquired by BPA from the 7(b)(2) Customers in the Program Case.

Conservation is defined in the Northwest Power Act as a resource. "'Resource' means … actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure." 16 U.S.C. § 839a(19). In addition, conservation is acquired by BPA under section 6. "The Administrator shall acquire such resources through conservation, implement all such conservation measures, and acquire such renewable resources which are installed by a residential or small commercial consumer to reduce load …" 16 U.S.C. § 839d(a)(1). Because conservation is acquired from 7(b)(2) Customers, it is

a Type 1 resource. This being the case, section 7(b)(2)(D) requires that any conservation being acquired by BPA must be included in the resource stack as a non-FBS resource and available to meet 7(b)(2) Customer load to the extent it is needed and it is among the least expensive resources available. *See* Issue 3, *supra*.

Section 7(b)(2)(D)(ii) describes the second type of resource as those "not committed to load pursuant to section 5(b)." These are resources owned or purchased by the 7(b)(2) Customers that are not dedicated to load. Section 5(b)(1) of the Northwest Power Act provides:

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds – (A) the capability of such entity's firm peaking and energy resources used in the year prior to the enactment of this Act to serve its firm load in the region, and (B) such other resources as such entity determines, pursuant to contracts under this Act, will be used to serve its firm load in the region.

16 U.S.C. § 839c(b)(1). As noted in section 3(19) of the Northwest Power Act, the term "resource" includes "electric power." 16 U.S.C. § 839a(19). Because section 5(b) applies to requirements determinations for both preference customers and investor-owned utilities, section 7(b)(2)(D)(ii) precludes BPA from including resources owned or purchased by 7(b)(2) Customers in the 7(b)(2) Case resource stack if such resources are committed to load by preference customers or investor-owned utilities.

Together, sections 7(b)(2)(D)(i) and (ii) result in a list of resources which are assumed to be available to meet 7(b)(2) Customer loads. The remainder of section 7(b)(2)(D) outlines how this list of resources is to be used to serve the 7(b)(2) Customers' loads and describes the third type of resources available to meet 7(b)(2) Case loads. BPA is to assume for the 7(b)(2) Case that any required additional resources "were the least expensive resources owned or purchased by public bodies or cooperatives." This means that 7(b)(2)(D)(i) and (ii) resources are stacked in order of cost and pulled from that stack to meet 7(b)(2) Customers' loads in order of least to greatest cost. Should these resources be insufficient to satisfy the General Requirements of 7(b)(2) Customers, section 7(b)(2)(D) provides the assumption that "... any additional needed resources were obtained at the average cost of all other new resources acquired by the Administrator." This third resource type consists of the other new resources acquired by BPA in an amount required to meet the 7(b)(2) Customers' remaining loads, the cost of which is determined by the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the relevant Five-Year Period.

12. Interpretation: Section 7(b)(2)(E) requires an assessment of the Quantifiable Monetary Savings that are realized by public body financing of resources that are in the resource stack.

Discussion:

Section 7(b)(2)(E) states that the Administrator is to assume that "the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal base system resources, identified under subparagraph (D) of this paragraph, … were not achieved." 16 U.S.C. § 839e(b)(2)(E). The legislative history adds some clarification to this language. "The cost of resources to meet these requirements are … (b) Costs of new resources, either actual or hypothetical, constructed or acquired by the public bodies and cooperatives as necessary to meet these preference customer load requirements using the financing costs of such agencies that would have resulted if actions of the Administrator under Section 6 of the Bill were not achieved." S. Rep. No. 272, 96th Cong., 1st Sess., 58 (1979), Appendix B.

This subsection provides that the 7(b)(2) Case is to assume that the cost of resources in the subsection 7(b)(2)(D) resource stack is to exclude any 7(b)(2) Customer's financing benefits due to BPA's purchase of the output of the resource.

13. Interpretation: Section 7(b)(2)(E) requires an assessment of the value of Reserve Benefits acquired by BPA due to the Northwest Power Act.

Discussion:

Section 7(b)(2)(E) states that the Administrator is to assume that "the quantifiable monetary savings, during such five-year period, to public body, cooperative and federal agency customers resulting from … reserve benefits as a result of the Administrator's actions under this chapter were not achieved." 16 U.S.C. § 839e(b)(2)(E). Reserve Benefits result from resources designated by BPA to provide reserves and BPA's restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these resources and restriction rights may be unavailable to BPA. Without the restriction rights, for example, BPA would have to incur the costs of providing an equivalent amount of reserves from another source. This subsection provides that the 7(b)(2) Case is to assume that cost reductions attributable to Reserve Benefits are not achieved in the 7(b)(2) Case. Therefore, the 7(b)(2) Case revenue requirement is to assume the extra cost of procuring the reserves provided to the Program Case.

SECTION 7(b)(2) OF THE PACIFIC NORTHWEST ELECTRIC POWER PLANNING AND CONSERVATION ACT

IMPLEMENTATION METHODOLOGY

February 2009

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Attachment 2

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DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act

I. Introduction

The Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act"), 16 U.S.C. § 839, confirms BPA's obligation to establish and revise BPA's rates for the sale and transmission of electric power. Section 7(b)(2) of the Northwest Power Act provides that:

> after July 1, 1985, the projected amounts to be charged for firm power for the general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if the Administrator …

makes a set of assumptions, outlined in the remainder of section 7(b)(2). These assumptions hypothetically remove the effects of certain provisions in the Northwest Power Act. In order to implement the provisions in section 7(b)(2), BPA has formulated a methodology that specifies how BPA will conduct the section 7(b)(2) rate test.

The implementation of section 7(b)(2) in any given BPA rate proceeding requires two distinct steps. The first step is to compare a set of annual rates developed under all the provisions of the Northwest Power Act before considering the effects of section 7(b)(2) (the Program Case), with a set of annual rates developed under the assumptions outlined in section 7(b)(2) (the 7(b)(2) Case). Both sets of rates are those applicable to public body, cooperative, and Federal agency customers (7(b)(2) Customers) and are based on the costs of power required to serve the General Requirements of those customers over the Five-Year Period.

If the rates in the Program Case are determined to be higher than those in the 7(b)(2) Case, then rate protection is to be afforded to preference customers and a second step is required. The allocated costs of the 7(b)(2) Customers must be reduced by the amount of rate protection afforded by the rate test and the difference allocated to other BPA rates pursuant to section 7(b)(3) of the Northwest Power Act. This potential reallocation must be made within the framework of sound ratemaking principles and BPA's statutory obligations.

II. Definitions

This section contains definitions applicable to section 7(b)(2). Terms identified in the Northwest Power Act have the same meaning in this section, unless further defined.

1. Relevant Rate Case: The section 7(i) wholesale power rate adjustment proceeding being conducted at the time the projections for section 7(b)(2) are made, and in which any adjustment to rates in accordance with section 7(b)(2) may be reflected.

2. General Requirements: The public body, cooperative, and Federal agency customers' electric power assumed in the Relevant Rate Case to be purchased from BPA, exclusive of new large single loads. General Requirements are limited to power purchased from BPA under section 5(b) of the Northwest Power Act; section 5(c) purchases from BPA are not included.

3. 7(b)(2) Customers: Those firm power customers of BPA that are listed in section 7(b)(2) of the Northwest Power Act as subject to the rate test, *viz.*, public bodies, cooperatives, and Federal agencies.

4. Applicable 7(g) Costs: The costs identified in section 7(g) of the Northwest Power Act that are also listed in section 7(b)(2), *viz.*, costs chargeable to 7(b)(2) Customers for conservation, resource and conservation credits, Experimental Resources, and Uncontrollable Events.

5. Uncontrollable Event: A discrete event which differs from the continuum of changing events that occur in nature, business, and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

6. Experimental Resources: Resources that are undergoing research and development and are funded by BPA in full or in part.

7. Five-Year Period: The rate recovery period of the Relevant Rate Case, plus the ensuing four years. If the Relevant Rate Case has more than a one-year rate recovery period, the Five-Year Period will be greater than five years.

8. Program Case: The entire process of calculating rates to be charged in the Five-Year Period of the Relevant Rate Case under the provisions of the Northwest Power Act other than section 7(b)(2), including all specific data, assumptions, and results.

9. 7(b)(2) Case: The entire process of calculating rates for the relevant Five-Year Period under the provisions of section 7(b)(2) of the Northwest Power Act, including all specific data, assumptions, and results.

10. Five Assumptions: The five differences between the Program Case and the 7(b)(2) Case specified in subsections (A) through (E) of section 7(b)(2) of the Northwest Power Act.

11. DSI Loads: Those loads of direct service industries (DSIs) that are forecast to be served by BPA, during the Five-Year Period, pursuant to section 5(d)(1) or 5(f) of the Northwest Power Act.

12. Within or Adjacent: Relating to DSI customer loads determined in accordance with section 7(b)(2)(A) to be electrically within or adjacent to the geographic service territories of 7(b)(2) Customers.

13. Quantifiable Monetary Savings: The change in annual costs attributable to differences in resource financing or Reserve Benefits.

14. Reserve Benefits: The annual financial value of (1) resources designated by BPA as providing reserves, or (2) interruptible load that forestalls a resource acquisition by virtue of the ability to curtail the load at a time when off-line generation would otherwise need to be available to start up and serve load during unexpected conditions.

III. Legal Interpretation

BPA first published a Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act in 1984. 49 Fed. Reg. 23,998 (June 8, 1984). The first Legal Interpretation presented BPA's interpretation of section 7(b)(2) of the Northwest Power Act, incorporating principles of statutory construction and a review of legislative history. In addition, BPA considered the views expressed in a series of informal meetings with interested persons and in comments received in response to the publication of an earlier notice of a draft Legal Interpretation. The scope of the notice was limited to those issues that relied on statutory language or legislative intent for resolution.

Concurrent with the consideration of this revision to the Implementation Methodology, BPA is proposing revisions to the Legal Interpretation. This Methodology incorporates changes to conform to revisions to the Legal Interpretation.

Briefly, BPA interprets section 7(b)(2) as follows:

1. Section 7(b)(2) limits the 7(b)(2) Case to the Five Assumptions listed in section 7(b)(2) and the secondary effects of those assumptions.

2. Implementation of section 7(b)(2), and any subsequent reallocation pursuant to section 7(b)(3), will not conflict with the requirements of section 7(a).

3. Applicable 7(g) Costs are to be excluded from the Program Case revenue requirements and the 7(b)(2) Case revenue requirements prior to further determination of the 7(b)(2) Case power costs.

4. The appropriate Five-Year Period is the rate recovery period for the applicable rate case plus the ensuing four years.

5. 7(b)(2) Customers' loads include DSI Loads that are Within or Adjacent to the 7(b)(2) Customers' service territories.

6. BPA will use Appendix B of the Senate Report to assist in determining which DSI Loads are Within or Adjacent to the geographic service boundaries of 7(b)(2) Customers.

7. All DSI Loads assumed to be placed on 7(b)(2) Customers will be treated as firm loads.

8. Section 7(b)(2)(B) necessitates an examination of Program Case contracts in the determination of "Federal base system resources not obligated to other entities."

9. Section 7(b)(2)(B) requires the allocation of resource pools to load pools in the Program Case to be reconsidered in the 7(b)(2) Case.

10. Section 7(b)(2)(C) requires the exclusion of all costs relating to the section 5(c) exchange, otherwise known as the Residential Exchange Program, from the 7(b)(2) Case. In addition, the loads and resources associated with the exchange will also be excluded from the 7(b)(2) Case.

11. Section 7(b)(2)(D) identifies three additional resource types assumed to be available to meet the 7(b)(2) Customers' remaining General Requirements when FBS resources are exhausted. Type 1 are those resources not included in the FBS that are actually acquired by BPA from 7(b)(2) Customers in the Program Case. Conservation is a Type 1 resource. Type 2 are those resources owned or purchased by the 7(b)(2) Customers and not dedicated to load by public agencies or investor-owned utilities pursuant to section 5(b). These two types of resources are to be stacked in order of cost and then pulled from the stack to meet 7(b)(2) Customers' loads as needed, least expensive first. Type 3 resources are additional acquired resources not included in the FBS, which are priced at the average cost of all new resources acquired by BPA from non-7(b)(2) Customers during the Five-Year Period.

12. Section 7(b)(2)(E) requires an assessment of the Quantifiable Monetary Savings that are realized by public body financing of resources that are in the resource stack.

13. Section 7(b)(2)(E) requires an assessment of the value of Reserve Benefits acquired by BPA due to the Northwest Power Act.

IV. The Program Case

In performing the 7(b)(2) rate test, the Program Case is the Five-Year Period projection of the average annual power rates for serving the General Requirements of the 7(b)(2) Customers conforming with all the provisions of the Northwest Power Act before considering the effects of section 7(b)(2). All rate proposal determinations, decisions, and assumptions for the rate recovery period regarding revenue requirements, loads, resources, cost allocation, and rate

design will be used. All data for the ensuing four years will be consistent with or extrapolated from rate recovery period data. Ratemaking methodologies, such as those based on the rate directives in the Northwest Power Act and those used to allocate costs and revenue adjustments to BPA customer classes, will be unchanged over the Five-Year Period.

If BPA uses its section 7(e) rate design discretion to implement an alternative tiered rate form, that rate design flexibility will be applied subsequent to the section 7(b)(2) rate test. In such cases, the rate test will continue to be performed with all ~~cost~~ costs allocated to, and all loads included in, the 7(b) load pool, without respect to the tiering of such ~~costs and~~ loads and related costs.

1. Load Forecast

A load forecast will be developed for every BPA rate proposal independent of any requirements for implementing section 7(b)(2). It will include estimates of BPA programmatic conservation savings for the forecast period. The treatment of power sales contracts that expire during the Five-Year Period will be the subject of each Relevant Rate Case. This forecast will provide the load estimates for the Program Case.

2. DSI Loads

A load forecast of purchases by DSIs from BPA will be developed for the Five-Year Period. This forecast, without consideration of the rate schedule under which the power is sold, will define the DSI Loads for the Program Case.

3. Resources

Regional resource generation studies are also conducted for BPA's rate proposals. These studies determine the capability of BPA's and the region's hydro and thermal resources for the Five-Year Period. The resource study results will be consistently applied through the Five-Year Period except as modified to reflect the start of commercial operation or retirement of generating resources and also for the planned effect or expiration of relevant contracts or purchases. Firm and secondary hydroelectric generation will be based on these studies. Assumptions about the level of surplus firm power sales for the Program Case will be the same as those made for the Relevant Rate Case.

4. Revenue Requirements, Including Residential Exchange Costs

BPA's repayment process will be used for the determination of BPA revenue requirements through the Five-Year Period. Costs will be projected over the Five-Year Period using budget estimates, when available. Estimates of future inflation and real cost escalation and planned additions to BPA's power system will be used when budget estimates are unavailable.

5. Surplus Firm and Secondary Sales

The Program Case establishes the forecast of revenues from surplus power sales, whether the surplus is firm or secondary.

6. Subtracting Applicable 7(g) Costs

Prior to comparing the Program Case rates to the 7(b)(2) Case rates, section 7(b)(2) directs that the Applicable 7(g) Costs are to be subtracted from the Program Case rate. To accomplish this, the amounts of Applicable 7(g) Costs allocated to the 7(b) rate pool will be removed from the Program Case rates. To do so, the allocated Applicable 7(g) Costs will be expressed as a unit rate comparable to the 7(b) rate and will be subtracted from the annual 7(b) rates to calculate the adjusted Program Case rates.

7. Summary Methodology for the Program Case

The procedures and data from the rate proposal cannot be described in detail in this document. They are properly rate case determinations that are outside the scope of the Methodology for implementing section 7(b)(2). The Section 7(b)(2) Methodology must be flexible enough to incorporate the procedures and data from the rate proposal for which the section 7(b)(2) rate test is being conducted. These procedures and data, as part of a BPA rate filing, are in turn subject to review and comment pursuant to section 7(i) of the Northwest Power Act. The Section 7(b)(2) Methodology can require only that the rate proposal procedures and data be modeled or incorporated as accurately as possible, which will be subject to examination during the Relevant Rate Case.

In summary, the Program Case will be BPA's best projection of its rates without considering the effects of section 7(b)(2). The exact procedures for the rate calculation in the Program Case cannot be determined until BPA has prepared its rate proposal. However, the rate test modeling will reflect the rate proposal procedures as completely as possible in producing the Program Case when the rate test is conducted for that rate proposal.

V. The 7(b)(2) Case

The language of section 7(b)(2) not only directs BPA to conduct a rate test for the 7(b)(2) Customers, but also provides a considerable amount of direction as to how the rate test is to be conducted. BPA's Legal Interpretation provides the general approach to developing the 7(b)(2) Case. Based on this, the 7(b)(2) Case will be modeled in the same way as the Program Case, except where section 7(b)(2) provides specific assumptions that modify the Program Case. The modeling of these Five Assumptions and their secondary effects may lead to different results than the underlying premises and ratemaking processes that will be held constant between the two cases. The remainder of this section outlines how the 7(b)(2) Case rate calculations for the Five-Year Period will be developed.

1. Load Forecast

The initial loads that will be used in the 7(b)(2) Case will be the same General Requirements as those used in the Program Case, except that they will not include estimates of programmatic conservation savings being acquired by BPA because conservation is a non-FBS resource. In addition, conservation is a resource acquired by the Administrator pursuant to section 6 and, therefore, conservation resources are required to be included in the 7(b)(2) Case resource stack. Because conservation resources must be included in the resource stack to be drawn to meet remaining loads if needed, they have not already been acquired, and therefore they cannot have reduced the loads of the 7(b)(2) Case. To remove the effects of the acquisition of conservation, the 7(b)(2) Customer loads will be increased by conservation being acquired by BPA. Power sales contracts that expire during the Five-Year Period, except for requirements and DSI contracts, will be recognized as expiring as scheduled. This forecast will provide the load estimates for the 7(b)(2) Case.

2. DSI Loads

DSI Loads will be examined on a plant-by-plant basis to reflect whether or not they are Within or Adjacent. All Within or Adjacent DSI Loads will be included in the General Requirements of the 7(b)(2) Customers during the Five-Year Period. DSI Loads not Within or Adjacent are assumed to be served by private utilities. The forecast operating levels of the DSIs that are transferred to public and private utilities are assumed to be served as 100 percent firm loads.

3. Resources

Section 7(b)(2)(B) requires the Administrator to assume that public body, cooperative, and Federal agency customers are served first with FBS resources, and 7(b)(2)(D) requires that additional resources be assumed to serve the remaining general requirements of the 7(b)(2) Customers. As in the Program Case, the FBS in the 7(b)(2) Case will be reduced by any contractual, statutory, or treaty obligations on these resources that were in existence prior to passage of the Northwest Power Act (statutory and treaty including the Canadian Entitlement return, the Hungry Horse Reservation, and Bureau pumping power).

Any contract that BPA enters into subsequent to December 5, 1980, that exchanges FBS capacity for energy, exchanges seasonal FBS energy, or for the sale of FBS capacity with the return of the energy, will be assumed only if there is FBS surplus to 7(b)(2) Customer needs. Therefore, the energy and revenue from such contracts will not be recognized in the 7(b)(2) Case unless there is an FBS surplus in the 7(b)(2) Case. If the FBS surplus does not allow full recognition of these contracts, then a *pro rata* share of energy and revenues will be recognized in the 7(b)(2) Case.

Any surplus FBS resources remaining after meeting FBS obligations, 7(b)(2) Customer loads, and contracts subsequent to December 5, 1980, will be assumed to be sold in the wholesale energy markets at the forecast price assumed in the Program Case for such sales.

If FBS resources, after meeting obligations, are insufficient to meet the loads of the 7(b)(2) Customers, then three types of additional resources can be added to serve those loads. These additional resources are defined in section 7(b)(2)(D) and are: (a) actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case, including conservation resources; (b) existing 7(b)(2) Customer resources not currently committed to regional load by preference customers or IOUs; and (c) all other needed resources, acquired at the average cost of actual and planned resource acquisitions by BPA from non-7(b)(2) Customers consistent with the Program Case. The Type 1 and Type 2 resources will be assumed to come online to meet the remaining General Requirements of the 7(b)(2) Customers after FBS service in order of least-cost first. The resources will then be brought online in the exact amount required to meet the 7(b)(2) Customers' remaining General Requirements. However, once brought online, the resources will remain online throughout the Five-Year Period, even if loads are lower in subsequent years. In such cases, the excess resources will be assumed to be sold at the average cost of all the excess resources and the revenues credited to the 7(b)(2) Case rates.

4. Revenue Requirement

Except for specific exclusions resulting from the Five Assumptions and their secondary effects, the revenue requirement for the 7(b)(2) Case will be the same as the Program Case. The specific exceptions are:

(1) all costs related to the Residential Exchange Program will be removed, including the identified BPA costs of implementing the program. Any costs included in the Program Case that are the result of a settlement of Residential Exchange Program claims will also be excluded;

(2) all costs of any acquisition of new resources will be removed;

(3) Applicable 7(g) Costs will be removed; that is, the costs of conservation, billing credits, experimental resources, and uncontrollable events.

In addition to these explicit exclusions, the secondary effects of their exclusion will be considered. Specifically, for example, the Program Case repayment study will be performed without the excluded costs to determine the interest and amortization applicable to the 7(b)(2) Case.

5. Surplus Firm and Secondary Sales

The load and resource situation in the 7(b)(2) Case may be considerably different from that in the Program Case. The increase in the region's firm load due to the 100 percent firm service to Within or Adjacent DSI Loads, a different load forecast for the 7(b)(2) Case due to conservation removal, and a potentially different set of resources all imply that a different level of surplus firm power may be projected for the 7(b)(2) Case than for the Program Case. The level of surplus firm sales in the 7(b)(2) Case will be determined in the same manner as it is in the Program Case. However, any sales of surplus firm power projected to be made in the Program Case to serve interruptible DSI Loads will not be made in the 7(b)(2) Case. Any firm surplus FBS in the 7(b)(2) Case will be assumed to be sold at the average rate of post-Act

contract sales in the Program Case. Any difference between costs allocated to surplus firm and revenues from the sale will be allocated to 7(b)(2) Customers.

Secondary energy generation of the region's hydroelectric system will also be assumed to be the same as in the Program Case. However, the secondary energy sales will be increased in the 7(b)(2) Case to reflect additional sales due to the removal of interruptible DSI Load.

6. Financing Benefits

Section 7(b)(2)(E)(1) requires that BPA assume that Quantifiable Monetary Savings to 7(b)(2) Customers resulting from reduced public utility financing costs for the first two types of non-FBS resources described above were not achieved in the 7(b)(2) Case. Therefore, any additional resources required to serve the General Requirements of 7(b)(2) Customers will not reflect the financing cost reductions implicit in resource acquisitions by public bodies. Non-conservation Type 1 and Type 2 resources that are already financed and constructed and that did not receive any financing benefit associated with having a BPA acquisition contract when originally constructed or when refinanced do not have their financing costs changed by the financing study.

A list of eligible resources will be developed, containing cost and sponsor information for each resource. For those resources actually acquired by BPA in the Program Case, and for those resources not dedicated to load and assumed available to BPA, BPA will estimate the financing costs for the resource sponsor assuming that BPA had not acquired the resource output. Finally, when detailed financing cost and sponsor information is not available for planned 7(b)(2) Customer resources, BPA will follow the same procedures, assuming projected public sponsored resource costs. Any changes in financing costs determined from this analysis will be included in the costs of the resources in the 7(b)(2) Case.

For conservation resources acquired by BPA, the financing benefits may include an increased amount of debt financing compared to the Program Case. The amount of debt financing assumed in the 7(b)(2) Case will be determined in the Relevant Rate Case.

7. Reserve Benefits

Section 7(b)(2)(E)(ii) requires BPA to assume that the Quantifiable Monetary Savings resulting from Reserve Benefits were not achieved. Reserve Benefits result from BPA's designated resources or restriction rights on loads provided for in power sales contracts. In the 7(b)(2) Case, these resources and restriction rights may be unavailable to BPA. Without the restriction rights, for example, BPA would incur the costs of providing an equivalent amount of reserves from another source. Therefore, it will be assumed that BPA will incur a level of costs for the benefit of public utilities based on the value of the reserves provided by the designated resources or restriction rights to the Program Case as determined in BPA's rate proposal. The value of reserves determination is currently based, in large part, on the cost of an alternative reserve resource. Also, if the level of reserves provided by the resources or restriction rights is insufficient in the 7(b)(2) Case, based on BPA planning criteria, then additional reserve resource costs will be added in the 7(b)(2) Case.

VI. Rate Test Computer Model

Conducting the section 7(b)(2) rate test requires the use of a computer model to develop the rate projections for the Program Case and the 7(b)(2) Case. The exact form of the Program Case procedures cannot be determined until the time of the Relevant Rate Case for which the rate test is being conducted. The 7(b)(2) Case is inextricably linked to the Program Case as a result of the general approach applied to modeling the 7(b)(2) Case. Therefore, to the maximum extent possible, the exact structure and form of the computer model should be the same as used in determining BPA's actual power rates.

VII. Comparison of Rates

For each of the two Cases, the Program and the 7(b)(2), the rate test model will produce a set of annual average energy rates for the Five-Year Period. These two sets of rates will be used to determine if a reallocation of costs pursuant to section 7(b)(3) is required. The relevant rates for the comparison from the Program Case are BPA's average annual 7(b) rate less Applicable 7(g) Costs. The relevant rates from the 7(b)(2) Case are the per-kilowatthour power costs of serving the General Requirements of the 7(b)(2) Customers.

The 7(b) rate in the Program Case will be developed in the same manner as it is in BPA's rate proposal. The 7(b)(2) rate in the 7(b)(2) Case will include the costs of resources required to serve the 7(b)(2) Customers, along with all other costs and revenue adjustments not excluded by the Five Assumptions and their secondary effects. These costs and revenue adjustments include, but are not limited to, BPA's administrative and general costs, the FBS allocation of contract revenue deficiencies, and secondary revenue credits.

Prior to comparison with the 7(b)(2) rates from the 7(b)(2) Case, the 7(b) rates from the Program Case will be reduced by the Applicable 7(g) Costs listed in section 7(b)(2). All the costs of BPA conservation programs, billing credits, Experimental Resources, and Uncontrollable Events that were allocated to the 7(b) rates will be subtracted. The reduced Program Case rates will then be compared to the 7(b)(2) rates to determine if the 7(b)(2) rates are lower, on average, than the Program Case rates.

The comparison between the Program Case and the 7(b)(2) Case rates will be conducted for the Five-Year Period and will consider the time value of money. Therefore, the two sets of rates will be discounted back to the beginning of the first year of the Relevant Rate Case at BPA's projected future nominal borrowing rate, and then a simple average will be computed over the Five-Year Period. The discounted average rates will be rounded to the nearest ~~tenth~~ hundredth of a mill per kilowatthour. If the simple average of discounted 7(b)(2) Case rates is less than that of the Program Case rates, then a determination of an amount of rate protection to be reallocated in BPA's rate proposal is required. The difference known as the 7(b)(2)rate test trigger amount will be rounded to the nearest hundredth of a mill per kilowatthour when performing the reallocation.

VIII. Determination of Rate Protection Amount

If it is determined that the results of the rate test require a reallocation of costs for BPA's rate proposal to effect the rate protection, then the amount to be credited to the 7(b)(2) Customers and reallocated to BPA's other non-PF Preference sales must be calculated. This credit reflects the fact that it is a rate period adjustment that is based on a Five-Year Period determination. The difference in average discounted rates (rounded to the nearest hundredth of a mill) will be multiplied by the preference customer loads for the Relevant Rate Case to determine the reduction in the 7(b)(2) Customers' rate period costs.

IX. Conclusion

The section 7(b)(2) rate test, up to and including the point at which the rate protection amount is determined, is conducted outside of the mainstream of BPA's rate development process. Although the rate test reflects the Five Assumptions and their secondary effects used in the rate proposal, the rate test has no impact on BPA rates until the rate protection amount is included in BPA's rate design. At this point, any adjustment made to reflect the rate test results in BPA rates must be done within the overall framework of the rate development process and of BPA's ratemaking objectives and statutory requirements. Therefore, the section 7(b)(2) rate test results will be included as a step in BPA's rate design process, consistent with other statutory provisions and BPA's ratemaking objectives.

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FINAL REPORT

TO

BONNEVILLE POWER ADMINISTRATION

ON

ESTIMATED FINANCING COSTS

FOR
2010 POWER RATE CASE
SECTION 7(b)(2) RATE TEST

January 21, 2009

PREPARED BY

PUBLIC FINANCIAL MANAGEMENT

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PFM Asset Management LLC
PFM Advisors

APPENDIX A TO:

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

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SECTION 1

PURPOSE OF REPORT

The purpose of this report is to provide our recommended financing costs that will be used by Bonneville Power Administration ("BPA") as inputs in their calculation of the "reduced public body and cooperative financing costs" as described in Section 7(b)(2)(E) of the Northwest Power Act. We also discuss certain assumptions and rationales used in arriving at these recommended financing costs. In providing the enclosed summary of our conclusions and assumptions, we have relied upon our professional experience and expertise in matters concerning the overall credit markets and the activities of BPA and other public and private utilities in the Pacific Northwest ("PNW") and throughout the country.

SECTION 2

INTRODUCTION

The Northwest Power Act requires that the Administrator of BPA periodically review and revise rates for the sale of Federal power and for the transmission of non-Federal power. As part of the process of reviewing and revising the rates for firm power to be charged its preference, direct-service industry ("DSI"), investor-owned utility ("IOU"), and other customers, the Administrator must follow the requirements of Section 7(b)(2) of the Northwest Power Act. Section 7(b)(2)(E) requires that the Administrator assume that:

> the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal Base System resources, identified under subparagraph (D) of this paragraph, and reserve benefits as a result of the Administrator's actions under this chapter were not achieved.

Section 7(b)(2)(D) specifies the assumptions to be made to meet public body, cooperative, and Federal agency customer (7(b)(2) Customers) loads. After meeting contractual obligations with Federal Base System ("FBS") resources, additional resources can be added to meet loads of the 7(b)(2) Customers. These additional resources can include actual and planned resources acquired from 7(b)(2) Customers, including conservation programs undertaken or acquired by BPA; existing 7(b)(2) Customer resources not dedicated to regional loads; and generic resources acquired from non-7(b)(2) Customers.

The quantifiable monetary savings associated with the "reserve benefits" described in Section 7(b)(2)(E)(ii) relate to reserves that could be made available to BPA by the nature of BPA's

contracts with its customers. In the WP-10 Initial Proposal, Power Services is assuming a small amount of DSI load (estimated in the range of 380-400aMW), with firm power deliveries sold at the Industrial Firm Power (IP) rate determined in the rate case. Power Services has informed PFM that it is hopeful that it will be able to negotiate contract amendments that will allow it to sell firm power to DSI loads for FY 2010-2011. Although prior DSI contracts have provided the Federal Columbia River Power System (FCRPS) with reserves through BPA's ability to restrict or interrupt portions of DSI loads, Power Services informs us that the DSI contracts' provisions to restrict or interrupt the load is uncertain. The Initial Proposal assumes a value on this interruptibility of $0.01/MWh. As in prior rate cases where BPA has served DSI loads with firm power in the Program Case, DSI loads are assumed to be served by utilities in the Northwest instead of BPA in the 7(b)(2) Case. The 7(b)(2) rate test requires the assumption that these utilities would have had to provide their own reserve resources, and that the utilities would finance reserve resources without BPA participation. In prior rate cases, BPA's analysis of the restriction rights value for the 7(b)(2) rate test has contained the assumption that financing costs associated with such reserves would be different if they were acquired by regional utilities. However, because the rights to restrict or interrupt this load is uncertain and because the Initial Proposal assumes the value associated with these rights to be insignificant to the 7(b)(2) rate test, the 7(b)(2) rate test financing cost study will not include resource acquisitions by the Joint Operating Agency (JOA) for the replacement of supplemental reserves provided by the DSIs.

This report provides our conclusions concerning estimated financing costs for BPA's public body, cooperative, and Federal agency customers to be used in the 7(b)(2) rate test described in the Northwest Power Act. The conclusions presented in this report represent our opinions as financial advisors familiar with the municipal and governmental utility credit markets and with bond issues for both public power agencies and IOUs in the Pacific Northwest. Given the assumptions noted in this report, our conclusions represent a probable situation, had the hypothetical situation described in the Northwest Power Act occurred.

SECTION 3
EXECUTIVE SUMMARY

This report derives and provides estimates of the interest rates and differentials associated with financing for the different classes of resources identified in Section 7(b)(2) of the Northwest Power Act. Prior 7(b)(2) rate tests have utilized both actual historical interest rates and projected future interest rate assumptions for several financing structures. Historical interest rate assumptions have been applied to the financing of prior expenditures for "Named Resources," conservation resources,

and other forms of generating resources. Projected future interest rate assumptions have been applied to the financing of prospective expenditures for potential conservation and generating resources. This report also derives and provides estimates of interest rates and differentials associated with the different classes of resources in the Program Case. In the case of certain Named Resources, actual historical financing costs were utilized. Table A contains a summary of historical and projected interest rate assumptions for various resource categories. It is important to note that Table A has been developed from the format provided in prior 7(b)(2) rate study analyses. The prior studies sought to provide historical and prospective interest rates for long-term, fixed-rate financings. As such, the rates provided in the prior studies were for level debt service financing structures with an assumed final maturity of roughly 30 years. In order to estimate the average interest rate for a 30-year financing, prior studies used various interest rate measures for bonds having a term of 25 years. We concur that the selection of interest rate indices having a 25-year term represents a reasonable estimate of the financing costs for 30-year, level debt service borrowings.

In Table A, we have again provided interest rate assumptions based on indices and market data for 25-year maturities, along with assumptions for 5-year, 10-year, 15-year, and 20-year maturities to finance conservation investments. (*See* Tables C through G in this report.)

The Program Case Interest Rates and 7(b)(2) Case Interest Rates shown in Table A below are derived from historical borrowing cost and interest rate information compiled for the purposes of the Section 7(b)(2) rate test. The historical interest rate differentials have been used as a reasonable basis for establishing assumptions for projected interest rate differentials for borrowing costs for the WP-10 rate period. It is important to note that the interest rate assumptions in Table A for Projected Conservation and Projected Generation expenditures are derived from historical interest rate averages over the past three years. Prior to the WP-07 Supplemental Section 7(b)(2) Rate Test Study, the interest rate assumptions were developed by averaging data over a 10-year period preceding the relevant Section 7(b)(2) Rate Test Study.

Current credit market conditions exhibit a degree of volatility and uncertainty that has not been experienced in several decades. This period began over a year ago, and there is no consensus as to how long it will last or how severe it will be. One clear impact of the current market environment is that interest rate differentials between various credit ratings are more pronounced than they have been in many decades. Until September 2008, the impact of recent credit market volatility had not been as pronounced in the governmental utility market sector examined by this report, as compared

TABLE A – Summary of Historical and Projected Interest Rate Assumptions

Resource	Program Case Interest Rate With BPA Backing	7(b)(2) Case Interest Rate Without BPA Backing	Interest Rate Differential Basis Points
Historical Named Resources			
Idaho Falls	Not Applicable	Not Applicable	Not Applicable
Cowlitz Falls (25Yr)	4.20% Actual (1)	4.25%	5
Projected Conservation – see notes (2) and (3)			
BPA Sponsored (25 Yr) Table C, page 14	4.56%	4.78%	22
BPA Sponsored (20 Yr) Table D, page 15	4.51%	4.73%	22
BPA Sponsored (15 Yr) Table E, page 15	4.37%	4.57%	20
BPA Sponsored (10 Yr) Table F, page 15	4.03%	4.24%	21
BPA Sponsored (5 Yr) Table G, page 15	3.58%	3.79%	21
Projected Generation			
Public (25 Yr) Table C, page 14	4.56%	4.78%	22
Non-7(b)(2) (25 Yr) Table H, page 18	5.96%	4.78%	-118

(1) Actual True Interest Cost of refunding issue sold August 24, 2003.

(2) The interest rates provided for various Projected Conservation investments are assumed for either BPA or JOA borrowings having the maturities so listed. In the WP-10 Section 7(b)(2) Rate Test Study, BPA assumes that conservation capitalized measures related to fiscal years 2001 through 2015 would be amortized and financed by a JOA over a period of 15 years. Conservation first-year expensed costs would be deferred and amortized and financed over a 1 to 15-year time period. During FYs 2006-2008, BPA issued $50 million in conservation bonds with 3 to 5 year terms. The weighted average term was 3.4 years, with a weighted average interest rate of 4.90%.

(3) During the 2010 Power Rate Case study period FY 2010 – FY 2015, BPA projects that it will borrow $262 million for conservation investments using 5-year maturities with a weighted average interest rate of 5.35%. The bonds will be issued through the U.S. Treasury so they are not comparable to the tax exempt rates included in the table.

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to lesser credit ratings. However, these market sectors – mid-to-high investment grade, tax-exempt, municipal utility bonds – have recently seen pronounced interest rate spread differentials between credit rating categories. In September and October of 2008, there were several weeks when the global credit markets, including the municipal bond market, were essentially closed to borrowers. Since that time, investment grade governmental utilities have had access to the market, albeit at interest rates and credit spreads that approach the highest levels in roughly 20 years. The new and

evolving nature of these market conditions presents a considerable challenge to the task of developing reasonable estimates to be used in the WP-10 rate case.

Given that:

1 - an important product of this report is the assumed interest rate differential between the Program Case Interest Rates and the 7(b)(2) Case Interest Rates,

2 – the interest rate differential between the two Cases is derived entirely by exploring historical interest rate data for various credit rating categories, and

3 – that current, and perhaps future market conditions are markedly different from conditions over the past ten years,

PFM is of the opinion that it would be inappropriate to develop assumptions for the upcoming six-year section 7(b)(2) rate test period by utilizing the past practice of averaging data from the prior 10-year period. Therefore, PFM recommends revising the prior practice of using the most recent 10 years of interest rate data and instead utilizing the most recent three years of data as a reasonable assumption for the purpose of the current rate test study. While future market conditions remain uncertain, PFM is of the opinion that utilizing the recent three-year period will reflect the likelihood that some degree of market disruption is likely to persist for at least a portion of the period covered by the current rate test study, and that the six-year nature of the rate test period leaves a considerable amount of time for the markets to return to some sense of normalcy.

As in prior rate test studies, a general observation from the data provided in Table A is that, for most financing categories, the 7(b)(2) Case interest rates are higher than those assumed in the Program Case. When there is a positive number in the "Interest Rate Differential" column, it represents that amount by which the 7(b)(2) Case interest rate is higher (or more costly) than the rate in the Program Case.

The interest rate averages listed above in Table A would serve as the assumed interest rates for the Program Case and 7(b)(2) Case for the prospective maturity terms outlined.

SECTION 4
ASSUMPTIONS

In developing our interest rate assumptions, we have used the types of financing that most likely would be, or could have been, used at the time of funding the hypothetical resources acquired

according to the terms of the 7(b)(2) rate test. We have relied upon common and accepted legal and financing structures for the hypothetical public financing entity that the 7(b)(2) Customers are assumed to have formed. Similarly, discrete borrowings undertaken by 7(b)(2) Customers and non-7(b)(2) Customers would be assumed to be financed using customary public financing methods for long-term, fixed-rate financing. Such assumptions as to legal and financing structure represent, in our opinion, the most prevalent means for financing large-scale resource acquisition programs similar to what BPA or its customers could have undertaken or would utilize in the future.

As noted above, the Northwest Power Act requires that an estimate be provided of the financing costs to customers in the 7(b)(2) Case, because the customers themselves would have to finance the acquisition of additional resources needed to meet their firm loads after BPA's FBS resources are exhausted. An assumption has been made in prior 7(b)(2) financing cost studies, with which we concur, that the 7(b)(2) Customers would have formed a Joint Operating Agency ("JOA") where the financing would have been the responsibility of the participant agencies in the financing. This would have been a similar, but not identical, legal structure to Energy Northwest and other JOAs such that underlying legal obligations would have been clearly enforceable.

The member agencies of the assumed JOA are listed in Attachment A along with their respective shares and credit ratings. All of the member agencies are assumed to have signed "take-or-pay agreements," such that each would pay for its proportionate share of the debt service on the financing regardless of whether or not the project produced the expected levels of output. In the event that one participant failed to pay its share of debt service, each remaining participant would be responsible for an increased level of debt service of up to 125 percent of the member agency's original commitment. Based on such a typical JOA financing structure, and in concurrence with the assumptions contained in prior 7(b)(2) financing cost studies, we have assumed that a financing by a JOA consisting of the assumed member agencies would have received and been able to maintain a rating in the "A" category from both Moody's and S&P, two well-regarded bond rating agencies. In the case of the JOA or 7(b)(2) Customer issuing revenue bonds with the advantage of a BPA "take-or-pay" or "capability" power sales contract, we have assumed that the financing would have received and maintained a rating in the "Aa/AA" category from both Moody's and S&P. BPA's current ratings are Aaa from Moody's and AA- from S&P. In PFM's opinion, the "Aa/AA" rating category represents a ratings category that contains the midrange of the divergent Moody's and S&P ratings. We utilize this assumption because there are interest rate databases for various rating categories, but there are no

databases for "split" ratings in those cases where there is a difference between the Moody's and S&P rating categories.

In estimating the financing costs for specific Named Resources, such as the Cowlitz Falls Project, we have assumed a rating based upon the particular sponsor's credit rating. Therefore, the ability of the Public Utility District No. 1 of Lewis County (Lewis County PUD), for example, to service its own load with the resource is also assumed in order to meet requirements for investment grade ratings from both Moody's and S&P. Similarly, we have estimated financing costs for other anticipated conservation and generation resource providers, assuming that suitable uses for the resource output were available.

SECTION 5

ASSUMPTIONS CONCERNING RESOURCE ACQUISITIONS

In previous rate cases, BPA has assumed the JOA would have undertaken two phases of resource acquisition. The first phase assumed the acquisition of peaking resources to replace the reserve benefits provided by the DSI load that are not provided in the 7(b)(2) Case. As outlined in the introduction, the amount and value of interruption or restriction rights for DSI loads during the rate test period are assumed to be very limited. A small amount of Supplemental Reserve purchases are included in the 7(b)(2) Case through market purchases. Therefore, the current 7(b)(2) study will not include resource acquisitions by the JOA for the replacement of supplemental reserves provided by the DSIs.

The second phase of resource acquisition program assumes the acquisition of individual projects involving conservation resource and generation resource programs sponsored by 7(b)(2) Customers as well as a variety of other sponsors. In prior years, BPA has acquired resources through its Competitive Resource Acquisition Program, unsolicited proposals, and BPA Billing Credit programs. In recent years, BPA has acquired wind and solar renewable resources along with small hydro and waste heat recovery resources through direct acquisitions.

The City of Idaho Falls and BPA entered into a replacement Power Purchase Agreement dated September 5, 2006, for the purchase of all power and energy produced from four hydroelectric generating plants operated by the City of Idaho Falls (the Idaho Falls Project). Lewis County PUD entered into a Power Purchase Agreement dated May 23, 1991, with BPA for the output of the Cowlitz Falls Hydroelectric Project (the Cowlitz Falls Project). BPA has solicited for resources through the

BPA Billing Credits Policy is contained in section 6(h) of the Northwest Power Act and the Competitive Resource Acquisition Program, which includes the Resource Contingency Program. Under the BPA Billing Credits Policy, BPA has contracted for the output of four projects consisting of South Fork Tolt, Wynocchee, Short Mountain Landfill, and Smith Creek. The total output of these four projects is approximately 20.0 aMW. Under the terms of the BPA Billing Credits Policy, BPA's obligation to purchase the output is subject to the availability of the resource and, therefore, we do not believe the existence of the BPA power purchase agreement to be material to the credit rating of the financing associated with these particular resources.

In general, the hypothetical financing agency consisting of the 7(b)(2) Customers would apportion the risks of resource acquisition due to non-completion, technical difficulties, or other factors among the member agencies in proportion to their ownership shares. Similarly, individual resource sponsors are assumed to accept such risks without allocation to third parties. Thus, the risks of non-completion or technical difficulties are not assumed to be factors that would impact the financing costs of particular resources.

We have assumed that all financings will utilize traditional fixed-rate debt with a level debt service structure. The revenue bonds or project financings issued by, or entered into by, 7(b)(2) Customers, non-7(b)(2) Customers, or other entities would have comparable features.

Financing of the Cowlitz Falls Project and the Idaho Falls Project is assumed to have occurred at the time when the sponsors of each of the projects issued revenue bonds to provide for the capital costs of each respective resource. Resources to be acquired from non-7(b)(2) Customers are assumed to be acquired on a project finance basis. In the Program Case, BPA would contract to purchase power output. In the 7(b)(2) Case, BPA would contract with the JOA.

In addition, it is assumed that all financings by 7(b)(2) Customers are structured to take full advantage of tax-exempt financing, subject to the provisions of applicable tax law. Also, we would note that Section 9(f) of the Northwest Power Act requires certain certifications by the Administrator prior to the acquisition of resources, which must be met in order that the exemption from gross income in section 103(a)(l) of the Internal Revenue Code of 1986 be achieved. As a result, the assumption is made for purposes of the resource acquisitions contemplated with BPA that the tax-exemption for financings will not be adversely affected and that BPA will be able to provide the certifications required under the Northwest Power Act.

We would also note that the assumed credit ratings on revenue bonds involving an obligation of BPA have remained stable in recent years. Uncertain water conditions, the financial requirements of BPA's resource acquisition programs, fish and wildlife issues, and other items are significant issues affecting the PNW and BPA's credit ratings. However, for the purposes of the 7(b)(2) rate test, no change in credit ratings is projected for BPA or the 7(b)(2) Customers as it pertains to the financing feasibility of particular resources financed with debt issued in the public credit markets.

SECTION 6
IDAHO FALLS PROJECT

On April 1, 1982, the City of Idaho Falls, Idaho, executed a Power Purchase Agreement whereby BPA agreed to a long-term purchase of the output of four hydroelectric generating plants to be constructed in the service territory of the City of Idaho Falls. The City of Idaho Falls provided for the capital costs of constructing the four hydroelectric generating plants with the proceeds of revenue bonds issued in 1981. These bonds were subsequently refinanced on multiple occasions. On September 5, 2006, the City of Idaho Falls and BPA executed a new five-year Power Purchase Agreement for the period October 1, 2006, through September 30, 2011.. This agreement states that it is the intent of the parties to negotiate a successor contract prior to the expiration of the current contract. Because the revenues of the City's Electric System (as defined) secure the City of Idaho Falls revenue bonds issued to finance the Project, we do not believe the existence of the BPA Power Purchase Agreement to be material to the credit rating of these bonds. Therefore, the cost of the Idaho Falls Project resource would not change as a result of the financing assumptions required by the 7(b)(2) rate case.

SECTION 7
COWLITZ FALLS PROJECT

On May 23, 1991, Lewis County PUD entered into an Amendatory Contract for Power Purchase (the Contract) whereby BPA agreed to enter into a long-term purchase of the output of a hydroelectric generating plant known as the Cowlitz Falls Project. BPA and Lewis County PUD agreed that Lewis County PUD would finance construction of the Cowlitz Falls Project through the issuance of revenue bonds, with BPA agreeing to pay to or on behalf of Lewis County PUD amounts equal to Project Power Costs (as defined) including Annual Debt Service (as defined) on such revenue bonds for the life of the Contract. On August 27, 1991, Lewis County PUD issued $171,095,000 in Public Utility District No.1 of Lewis County, Washington, Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991. The bonds were rated Aa/AA with annual debt service payments of approximately $13,465,000

and a final maturity of October 1, 2024. The callable bonds of this series were again refunded on August 23, 1993. The remaining 1991 bonds and the callable bonds issued in 1993 were refunded again on June 19, 2003.

Under the terms of the Contract, the primary source of security for the bonds is revenue received from BPA pursuant to the Contract and a Payment Agreement. Under the Contract, BPA is obligated to pay all project costs, including debt service, whether or not the project is completed or power is delivered. If BPA does not make payment under the Contract, it is obligated to pay debt service under the Payment Agreement directly to the bond trustee. Debt Service on the bonds, along with the payment of operating and maintenance (O&M) expenses of the project, have priority over payments of BPA's Treasury debt and repayment of the Federal investment in the Columbia River Power System.

Because the revenues from the Contract and the Payment Agreement secure Lewis County PUD’s revenue bonds issued to finance the Project, we believe that the Contract and Payment Agreement are the primary support for the current credit ratings. BPA retains the "dry hole risk" for the Project and is obligated to pay debt service on the Bonds for their full term whether the Project is operating or not. For the purposes of the 7(b)(2) rate test, Lewis County PUD is assumed to accept the "dry hole risk" and that the Cowlitz Falls Project output would be dedicated to serving Lewis County PUD’s own load.

The original bonds were priced on Tuesday, August 27, 1991, with a True Interest Cost of 7.10 percent. The refunding Bonds priced on Tuesday, August 23, 1993, had a True Interest Cost of 5.61 percent. The refunding Bonds priced on June 19, 2003, had a True Interest Cost of 4.20 percent. Of the $146,210,000 of bonds sold in 2003, $135,930,000 was guaranteed by municipal bond insurance companies and rated AAA. The uninsured bonds maturing in years 2005 through 2007 were rated Aa2/AA-. As stated earlier, we believe that a bond issued on behalf of the 7(b)(2) Customers would have carried a rating in the A category. During the months preceding the Lewis County sale, there were several bond issues sold for A-rated electric utilities. However, in most every case, these bonds were also guaranteed by a municipal bond insurance policy and rated AAA. Interest rates on these insured bonds were comparable to those of the Lewis County bonds. In our opinion, the net financing cost differential between AA- and A-rated bonds that were both backed by AAA-rated insurance policies would have been a function of the price charged by the insurance companies. In the case of the Lewis County bonds, one insurance policy for a portion of the bonds was priced at 0.33 percent of the total amount of insured debt service. The other policy, applied to a

different grouping of bonds, was priced at 0.475 percent of insured debt service. The amount of these premiums is taken into account in the calculation of the 4.20 percent True Interest Cost on the bonds. In our opinion, at the time the Lewis County bonds sold, an approximate market insurance premium for an A-rated issuer would have been approximately 0.75 percent of insured debt service. A recalculation of the Lewis County True Interest Cost with the 0.75 percent assumed insurance premium produces a rate of 4.25 percent. In our opinion, we believe that the borrowing advantage to the 7(b)(2) Customers from the BPA backing is approximately equal to the 5 basis point differential between the two True Interest Costs.

SECTION 8
JOA BORROWING COSTS

For purposes of establishing assumptions for JOA borrowing costs, it is appropriate to utilize a historical interest rate methodology, as was the case with 7(b)(2) financing cost studies conducted prior to the WP-07 and WP-07 Supplemental Power rate cases. For pre-WP-07 financing cost studies, 7(b)(2) historical assumptions were based upon an analysis of actual bond issues for selected public power agencies for the period from January 1, 1982, to March 8, 1999.

The 2002 Section 7(b)(2) Rate Test Study recognized: (1) the diminishing data set of A-rated public power bonds due to the increasing use of AAA bond insurance, and (2) the existence of useful market indices such as the Bloomberg Capital Markets fair value yield curves. The Bloomberg Capital Markets calculates daily indexes for several rating categories and maturity ranges for power revenue bonds. The information appears to be generally consistent with information included from prior years, based upon the actual issuance of power revenue bonds by different rated issuers. The Bloomberg yield curves provide data for electric revenue bonds of several credit rating categories, including bonds rated A-, A+, AA-, and AA+. In order to estimate rates for bonds in the A and AA rated categories, we calculated the average of published rates for the A- and A+ categories for the A-rated data, and took the average of published rates for the AA- and AA+ categories for the AA rated data. Interest rate estimates are for financings with level debt service and a 30-year final maturity. The Bloomberg rates for 25-year maturities were used as the best estimates of financing costs for this financing structure.

These averages for FY 2004 and prior fiscal years are found in Table B. Table B provides the following information:

(1) the annual average of the Revenue Bond Index,

(2) the calculated hypothetical AA rated (and thus BPA-backed) average financing cost,

(3) the calculated hypothetical A rated (and thus JOA-backed) average financing cost, and

(4) the interest rate differential between (3) and (4) above for fiscal years prior to 2004.

For more recent years' interest rate assumptions, and for the WP-10 Initial Proposal for FY 2010-2011, we suggest utilizing a similar methodology for establishing the estimated rates for A and AA rated electric revenue bonds. We again used the database of Bloomberg interest rates for AA rated and A rated 25-year tax-exempt electric revenue bonds as the best proxies for BPA and JOA borrowing costs. However, PFM suggests a departure from the prior practice of developing the assumptions for financing costs that utilized historical interest rates over the most recent 10 years in the 2007 Power Rate Case and prior studies. As discussed on pages 5 and 6 of this report, volatility in the credit markets calls for a change in how PFM would develop reasonable assumptions to be used in the WP-10 7(b)(2) Case. As was the case with our Final Financing Study for the WP-07 Supplemental Final Proposal, PFM recommends revising the prior practice of using the most recent 10 years of interest rate data, and instead utilizing the most recent 3 years of data as a reasonable assumption for the purpose of the financing analysis for the Section 7(b)(2) Rate Test Study. While future market conditions remain uncertain, PFM is of the opinion that utilizing the recent 3-year period will reflect the likelihood that some degree of market disruption is likely to persist for at least a portion of the period covered by the current rate test study. For this reason, we have based our future interest rate assumptions for each of the various financing structures on the data from October 15, 2005, and forward.

For the current financing cost study, we have been advised by BPA personnel that the financing terms for conservation investments would be for a 15-year term for the capitalized portion of each year's investment. The first-year expensed conservation costs will be treated as deferred charges (SFAS #71) and financed over a 1- to 15-year time period as determined during the course of the rate case. Tables D, E, F, and G below provide various historical and projected interest rate assumptions for borrowings with final maturities of 20, 15, 10, and 5 years.

TABLE B - Historical Interest Rate Assumptions From Prior 7(b)(2) Rate Studies

FY End 9/30	Revenue Bond Index	BPA Rate	JOA Rate	Difference
1982	13.25%	12.65%	13.31%	0.66%
1983	10.13%	9.86%	10.47%	0.61%
1984	10.43%	10.69%	10.74%	0.05%
1985	9.90%	10.35%	10.10%	-0.25%
1986	8.26%	8.49%	8.42%	-0.07%
1987	7.68%	7.77%	7.68%	-0.09%
1988	8.40%	8.50%	8.48%	-0.02%
1989	7.17%	7.01%	7.13%	0.12%
1990	7.51%	7.62%	7.49%	-0.13%
1991	7.20%	6.96%	7.02%	0.06%
1992	6.69%	6.33%	6.35%	0.02%
1993	6.06%	5.73%	5.81%	0.08%
1994	6.08%	5.63%	5.98%	0.35%
1995	6.57%	6.34%	6.51%	0.17%
1996	6.01%	5.80%	5.96%	0.16%
1997	5.87%	5.61%	5.76%	0.15%
1998	5.41%	5.15%	5.31%	0.16%
1999	5.41%	5.14%	5.24%	0.10%
2000	6.07%	5.82%	5.92%	0.10%
2001	5.53%	5.26%	5.42%	0.16%
2002	5.42%	5.10%	5.34%	0.24%
2003	5.15%	4.89%	5.19%	0.30%
2004	5.13%	4.87%	5.10%	0.23%

Based on the Bloomberg Fair Market yield curves over the past three years, the average AA-rated, 25-year electric revenue bond yield was 4.56 percent. This figure represents a 22 basis point advantage relative to the 4.78 percent average for the A-rated average for the comparable period. Table C provides these figures for the past three fiscal years.

TABLE C – Recent Average AA and A Rated, 25-Year Electric Revenue Bonds

Year End 10/15	Program Case AA Bloomberg BPA Rate	7(b)(2) Case A Bloomberg JOA Rate	Difference
2006	4.51%	4.69%	0.18%
2007	4.41%	4.61%	0.20%
2008	4.75%	5.04%	0.29%
Averages	4.56%	4.78%	0.22%

TABLE D – 20-Year Term Structure Interest Rate Assumptions

Year End 10/15	Program Case ‘AA’ Bloomberg BPA Rate	7(b)(2) Case ‘A’ Bloomberg JOA Rate	Difference
2006	4.45%	4.65%	0.20%
2007	4.40%	4.60%	0.20%
2008	4.68%	4.94%	0.26%
Averages	4.51%	4.73%	0.22%

TABLE E – 15-Year Term Structure Interest Rate Assumptions

Year End 10/15	Program Case ‘AA’ Bloomberg BPA Rate	7(b)(2) Case ‘A’ Bloomberg JOA Rate	Difference
2006	4.31%	4.50%	0.19%
2007	4.33%	4.50%	0.17%
2008	4.47%	4.72%	0.25%
Averages	4.37%	4.57%	0.20%

TABLE F – 10-Year Term Structure Interest Rate Assumptions

Year End 10/15	Program Case ‘AA’ Bloomberg BPA Rate	7(b)(2) Case ‘A’ Bloomberg JOA Rate	Difference
2006	4.07%	4.23%	0.16%
2007	4.03%	4.23%	0.20%
2008	3.98%	4.26%	0.28%
Averages	4.03%	4.24%	0.21%

TABLE G – 5-Year Term Structure Interest Rate Assumptions

Year End 10/15	Program Case BPA Rate - /1	7(b)(2) Case A Bloomberg JOA Rate	Difference
2006	3.72%	3.88%	0.16%
2007	3.77%	3.98%	0.21%
2008	3.24%	3.52%	0.28%
Averages	3.58%	3.79%	0.21%

Note 1 - During the WP-10 rate test period, FY 2010-FY 2015, BPA projects that it will borrow $262 million for conservation investments using five-year maturities with a weighted average interest rate of 5.35%. The bonds will be issued through the U.S. Treasury, so they are not comparable to the tax exempt rates included in the table.

The period averages listed above would serve as the assumed interest rates for the WP-10 7(b)(2) rate test prospective 20, 15, 10, and 5-year financings. To determine the rates for bonds issued with maturities between 5 and 10 years, it would be reasonable to interpolate the rates between the 5- and 10-year maturities. For example the rate for 6-year maturities would represent the 5-year maturity plus 1/5th of the difference between 5 and 10-year maturities.

In our opinion, the above-assumed projected borrowing rates are reasonable estimates for borrowing costs of municipal issuers during the 2010-2015 time period. Many factors influence the movement of tax-exempt interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are the timing of particular financings, the absolute levels of interest rates, the perceived credit quality of particular issuers, and the overall supply and demand for tax-exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

SECTION 9

NON-7(b)(2) CUSTOMER BORROWING COSTS

Private developers, industrial companies, utility subsidiaries, and governmental and quasi-governmental entities all represent viable sponsors for developing power projects whose output could be made available to BPA. Financing vehicles available to project sponsors will be either recourse, where the sponsor's balance sheet is relied upon for credit support, or non-recourse. In a non-recourse project financing, the strength of the project, not the strength of the sponsor, provides the support for the debt. Project financings would derive considerable financing benefits from inclusion of a BPA power purchase contract.

For the purposes of this analysis, it is assumed that BPA would enter into an all-encompassing power purchase agreement, whereby BPA would be obligated to pay an amount sufficient to cover a project's fixed and variable costs. As a result, the project's financing should be indifferent to the level of electricity actually purchased. Other factors, including power delivery requirements, security deposits, performance criteria, regulatory out provisions, milestone criteria, force majeure events, security interests, events of default, and remedies upon default, are presumed to be resolved in a fashion that enables a project to be financed upon standard commercial terms.

Project sponsors that are private entities may or may not be able to qualify for tax-exempt financing for a particular project and generally may do so only where a facility qualifies as an "exempt facility," such as a waste to energy facility. Projects financed with tax-exempt financing would likely occur at interest rates comparable to those for the hypothetical JOA discussed in Section 8. Projects financed with private sources of capital would likely be financed with high leverage, which is usually 75 or 80 percent but can be as much as 100 percent, which allows for a minimization of equity investment by the project sponsor. We assume that a project financing with a BPA contract would provide the means for securing debt financing at pricing that would be at the upper end of the quality range for similar projects. The perceived credit quality of the BPA contract obligation among potential financing sources would increase financing options for a given project.

Pre-2007 7(b)(2) rate test studies assumed that private debt financing for a project with a BPA contract could have been arranged at 50 basis points over the lender's cost of funds, which was assumed to have been the six-month's London Interbank Offered Rate (LIBOR), with 100 percent financing of project costs. These pre-2007 financing studies then adjusted for the possible effects of entering into interest rate swaps or conversion agreements, which could have the effect of fixing the interest rates on all or a portion of a financing for a period of time or the remaining term to maturity for the transaction. In order to adjust the variable LIBOR interest rates to an estimated fixed interest rate for comparison purposes, prior financing studies assumed a 50 basis point addition to the LIBOR-based interest rates to represent the amortized cost of an interest-rate swap.

Once again, the greater amounts of historical data and proliferation of market indices allowed us to refine the methodology from that used in the pre-2007 rate test studies. For more recent years' interest rate assumptions, and for the WP-10 Initial Proposal, we suggest utilizing the Bloomberg database of interest rates for AA rated, 25-year taxable utility bonds as the best proxy for potential non-7(b)(2) project financing costs. As previously described, we have based our future interest rate assumptions for each of the various financing structures on the recent three-year data set from October 15, 2005, to October 15, 2008. Table H below provides the past three years' averages for the Bloomberg AA rated, 25-year utility bonds as compared to the JOA financing costs assumed for the same periods. Again, the JOA financing cost assumptions are those provided in Section 8.

TABLE H - Recent Average Bloomberg AA and A Rated, 25-Year Electric Revenue Bonds

Year End 10/15	AA Bloomberg Taxable Utility Non 7(b)(2) Rate	A Bloomberg Tax-Exempt Bond JOA Rate	Difference
2006	5.89%	4.69%	-1.20%
2007	5.83%	4.61%	-1.22%
2008	6.16%	5.04%	-1.12%
Averages	5.96%	4.78%	-1.18%

In our opinion, the above-assumed borrowing rates are reasonable estimates based upon the actual borrowing costs of taxable and tax-exempt borrowers during the indicated time periods. Many factors influence the movement of interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are the timing of particular financings, the absolute levels of interest rates, the perceived credit quality of particular issuers, and the overall supply and demand for tax-exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

ATTACHMENT A

PARTICIPATION IN HYPOTHETICAL PUBLIC FINANCING ENTITY (JOA)

PARTICIPANTS	AVERAGE FINANCIAL RATING[1]	% SHARE[2]
Generators:		
Eugene Water and Electric Board	A	3.41%
Seattle	A	12.12
Tacoma	A	6.24
PUD #1 of Chelan County	AA	4.12
PUD #1 of Clark	A	5.58
PUD #1 of Cowlitz County	A	6.45
PUD #1 of Douglas County	AA	0.78
PUD # 2 of Grant County	AA	5.92
PUD #1 of Pend Oreille County	BBB	1.20
PUD #1 of Snohomish County	AA	8.48
SUBTOTAL – GENERATORS (10)	A	54.29%
Non-Generators:		
Central Lincoln County PUD	A	1.61
Clallam County PUD #1	A	1.03
Clatskanie PUD	BBB	1.30
Flathead Electric Coop	NR	1.92
Franklin PUD	A	1.18
Inland Power & Light	NR	1.12
City of McMinnville	A	1.11
City of Richland	A	1.03
Springfield	A	1.05
Umatilla Electric Cooperative Association	NR	1.25
Wells Rural Electric Cooperative	NR	1.06
PUD #1 of Benton County	A	2.06
PUD #1 OF Grays Harbor County	A	1.45
PUD #1 of Lewis County	A	1.53%
SUBTOTAL – NONGENERATORS WITH GREATER THAN 1% SHARE (14)	A	18.70%
SUBTOTAL – REMAINING NONGENERATORS (113)	NA	27.01%
TOTAL (117)	A	100.00%

Note 1 – Rating represents the average of the latest reports issued by Standard and Poor's, Moody's, and Fitch rating agencies as of November 2008. The average rating is calculated by assigning a score, 1 to 10, with 1 being a 'AAA' and 10 being a 'BBB-", to the top ten rating categories for each agency and then taking the average score for each issuer. The average score was then assigned a rating of either 'AAA', 'AA', 'A', or 'BBB' based on the range with which it fell. NR designation stands for "not rated."

Note 2 – Percentage shares of participation in the JOA are based on the projected utility Total Retail Loads in relation to total regional Consumer Owned Utility loads.

APPENDIX B

Section 7(b)(2)
Section 7(b)(2) Rate Test Study and Documentation

Rates Analysis Model - Resource Stack

GDP Inflator / Deflator Tables

Accounting / Financing Treatment of Expensed Conservation
Analysis and Documentation

WP-10 Initial Rate Proposal

WP-10-E-BPA-06

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Accounting / Financing Treatment of Expensed Conservation

Introduction - Summary Information - Table of Contents

The detailed amounts and costs for non-conservation resources are contained in Appendix C to the 7 (b)(2) Study. The summary resource cost values that are contained in the resource stack are presented in 2010 dollars.

The detailed amounts and costs for conservation resources are contained in Appendix D to the 7 (b)(2) Study. The summary conservation resource cost values that are contained in the resource stack are presented in 2010 dollars.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Rates Analysis Model - Resource Sort Spread Sheet Example

7b2 New Resource Sort

All Costs are in 2010 Dollars

NO LOST REVENUES INCLUDED IN COSTS

A		B	C	D	E	F	G	H	I	J	K	L	M	M
Project		Nameplate (MW)	Interest Rate (%)	Capital Investment ($ooo)	Annual O & M ($ooo)	Annual Fuel ($ooo)	Conser. First Year Amort.	Capacity Factor	Life [/1]	Annual Capital Cost ($ooo)	Total Discounted Capital Cost ($ooo)	Total Discounted O & M and Fuel ($ooo)	Total Cost Dollars per AMW ($)	Total Cost Mills per KWH
BPA & Public Resources - Resources are listed in least cost first order.														
BPA PROG CONS	2004	31.40	4.57	22,724	18,502	0	$4,132	100	15	2,126	20,731	17,432	81,025	9.25
BPA PROG CONS	2001	18.70	4.57	71	24,855	0	$5,550	100	15	7	65	23,418	83,717	9.56
IDAHO FALLS ND	1982	18.50		0	6,115	0		100	60	0	0	99,718	89,836	10.26
BPA PROG CONS	2006	30.20	4.57	16,438	30,761	0	$6,869	100	15	1,538	14,996	28,982	97,082	11.08
BPA PROG CONS	2007	28.50	4.57	11,454	41,500	0	$9,267	100	15	1,072	10,449	39,100	115,903	13.23
BPA PROG CONS	2003	25.20	4.57	27,500	20,758	0	$4,635	100	15	2,573	25,088	19,558	118,109	13.48
BPA PROG CONS	2005	20.00	4.57	16,720	25,443	0	$5,682	100	15	1,564	15,253	23,972	130,750	14.93
BPA PROG CONS	2002	26.10	4.57	34,587	21,005	0	$4,690	100	15	3,236	31,553	19,790	131,145	14.97
BPA PROG CONS	2008	34.80	4.57	8,214	65,071	0	$14,531	100	15	769	7,493	61,308	131,804	15.05
BOARDMAN PUBLIC ND	1980	49.71			16,104	0		100	30	0	0	223,099	149,601	17.08
COWLITZ FALLS	1994	26.00	4.25	0	3,598	0		100	60	11,620	189,488	58,673	159,077	18.16
BPA PROG CONS	2009	40.10	4.57	27,760	77,167	0	$17,232	100	15	2,597	25,324	72,704	162,974	18.60
BPA PROG CONS	2015	38.80	4.57	43,034	83,127	0	$18,562	100	15	4,026	39,259	78,320	202,026	23.06
BPA PROG CONS	2014	38.80	4.57	43,899	83,935	0	$18,743	100	15	4,107	40,048	79,082	204,689	23.37
BPA PROG CONS	2013	38.80	4.57	44,788	84,925	0	$18,964	100	15	4,190	40,859	80,014	207,685	23.71
BPA PROG CONS	2012	38.80	4.57	45,700	85,910	0	$19,184	100	15	4,276	41,691	80,942	210,709	24.05
BPA PROG CONS	2011	34.60	4.57	38,325	84,552	0	$18,881	100	15	3,586	34,963	79,663	220,858	25.21
BPA PROG CONS	2010	31.20	4.57	32,300	85,546	0	$19,103	100	15	3,022	29,466	80,599	235,183	26.85
BILLING CREDITS	1996	10.14		0	0	0		100	30	5,268	72,981	0	239,911	27.39
WAUNA-Steam-Cogen.	1996	21.70		0	11,463	0		100	30	0	0	158,811	243,950	27.85
Resources Not Included In the Resource Stack:														
PRIEST RAPIDS 1959 ND	1959	14.90		0	2,932	0		100	70	0	0	48,491	46,492	5.31
WANAPAM 1963 ND	1963	14.80		0	3,713	0		100	70	0	0	61,408	59,274	6.77
NINE CANYON WIND PROJ. ND	2008	13.52		0	8,751	0		100	20	0	0	100,864	373,018	42.58

Note 1 - The number of years under the Life column heading represents the estimated remaining useful life of the resource.

BPA's 2010 Wholesale Power Rate Case
BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2010 Rate Case - 7(b)(2) Resource Stack
Nominal Dollars Corresponding to the Historical Year of Acquisition
($ 000)

	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amortization Period Years[2]
2001 Conservation	18.7	19,905.0	57.0	19,962.0	15
2002 Conservation	26.1	17,143.0	28,227.0	45,370.0	15
2003 Conservation	25.2	17,286.0	22,900.0	40,186.0	15
2004 Conservation	31.4	15,821.0	19,431.0	35,252.0	15
2005 Conservation	20.0	22,446.0	14,750.0	37,196.0	15
2006 Conservation	30.2	28,014.0	14,970.0	42,984.0	15
2007 Conservation	28.5	38,860.0	10,725.0	49,585.0	15
2008 Conservation	34.8	62,393.0	7,876.0	70,269.0	15
2009 Conservation	40.1	75,611.0	27,200.0	102,811.0	15
Subtotal[1]	255.0				
2010 Conservation	31.2	85,546.0	32,300.0	117,846.0	15
2011 Conservation	34.6	86,263.0	39,100.0	125,363.0	15
2012 Conservation	38.8	89,482.0	47,600.0	137,082.0	15
2013 Conservation	38.8	90,257.0	47,600.0	137,857.0	15
2014 Conservation	38.8	91,012.0	47,600.0	138,612.0	15
2015 Conservation	38.8	91,946.0	47,600.0	139,546.0	15
Cumulative Savings	**476.0**	**$831,985.0**	**$407,936.0**	**$1,239,921.0**	
Percentages		**67.10%**	**32.90%**	**100.00%**	

Notes:

Note 1 - The amount of conservation in the resource stack for FY2001-2009 (255.0 aMW) together with billing credit resources contained in the resource stack of 10.1 aMW establish the amount of the load resource balance difference between the Program Case and the 7(b)(2) Case at the start of the Rate Test Period amounting to 265.1 aMW.

Note 2 - Historical conservation investments that occurred prior to FY 2001 will have been fully amortized before the end of the rate test period in FY 2015 based on a composite useful life of 15 years in the 7(b)(2) Case. These resources are viewed as obsolete conservation investments that are not includable in the 7(b)(2) resource stack.

BPA's 2010 Wholesale Power Rate Case

BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures

BPA 2010 Rate Case - 7(b)(2) Resource Stack - Annual Investments and Savings

INVESTMENTS IN 2010 DOLLARS

($ 000)

Inflator / Deflator Adjustment Factor[1] To Change To 2010 $$$		Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amortization Period Years
0.800837	2001 Conservation	18.7	24,855.2	71.2	24,926.4	15
0.816124	2002 Conservation	26.1	21,005.4	34,586.7	55,592.1	15
0.832725	2003 Conservation	25.2	20,758.4	27,500.1	48,258.5	15
0.855097	2004 Conservation	31.4	18,502.0	22,723.7	41,225.7	15
0.882206	2005 Conservation	20.0	25,443.0	16,719.5	42,162.5	15
0.910697	2006 Conservation	30.2	30,761.1	16,438.0	47,199.1	15
0.936392	2007 Conservation	28.5	41,499.7	11,453.5	52,953.2	15
0.958847	2008 Conservation	34.8	65,070.9	8,214.0	73,284.9	15
0.979842	2009 Conservation	40.1	77,166.5	27,759.6	104,926.1	15
	Subtotals	255.0	325,062.2	165,466.3	490,528.5	
	Percentages		66.27%	33.73%	100.00%	
1.000000	2010 Conservation	31.2	85,546.0	32,300.0	117,846.0	15
1.020232	2011 Conservation	34.6	84,552.3	38,324.6	122,876.9	15
1.041582	2012 Conservation	38.8	85,909.7	45,699.7	131,609.4	15
1.062788	2013 Conservation	38.8	84,924.7	44,787.9	129,712.6	15
1.084313	2014 Conservation	38.8	83,935.2	43,898.8	127,834.0	15
1.106094	2015 Conservation	38.8	83,126.8	43,034.3	126,161.1	15
	Subtotals	221.0	507,995.4	248,045.6	756,041.0	
	Percentages		67.19%	32.81%	100.00%	
	Cumulative Savings	**476.0**	**833,057.6**	**413,511.9**	**1,246,569.5**	
	Percentages		66.83%	33.17%	100.00%	

Notes:

Note 1 - The Inflator / Deflator Indices are based on Global Insight data, The U.S. Economy: The 30-Year Focus, August 2008, Base Case Scenario, adjusted to make FY2010 the base year with a inflator /deflator value of 1.000.

BPA's 2010 Wholesale Power Rate Case
BPA 2010 Rate Case - 7(b)(2) Resource Stack

Inflation Adjustment Factors

Current 2008 GDP Deflator Fcst (Update)						Fiscal Year Cumulative
	Global Insight CY 2008 FORECAST	CY 2008 FORECAST	BPA FY2008 FORECAST	BPA FY2008 FORECAST		FY 2008 [2, 3] CUMULATIVE PRICE ADJUSTMENT INDEX
YEAR	CalendarYear Index	CalendarYear % Change [2]	Fiscal Year Index	Fiscal Year % Change [2]		(Base Year 2010)
1997	0.75					
1998	0.76		0.758			
1999	0.77	1.32%	0.768	1.32%	1999	0.771859
2000	0.78	1.30%	0.778	1.30%	2000	0.781910
2001	0.80	2.56%	0.795	2.19%	2001	0.798995
2002	0.82	2.50%	0.815	2.52%	2002	0.819095
2003	0.83	1.22%	0.828	1.60%	2003	0.832161
2004	0.86	3.61%	0.853	3.02%	2004	0.857286
2005	0.88	2.33%	0.875	2.58%	2005	0.879397
2006	0.91	3.41%	0.903	3.20%	2006	0.907538
2007	0.94	3.30%	0.933	3.32%	2007	0.937688
2008	0.96	2.13%	0.955	2.36%	2008	0.959799
2009	0.98	2.08%	0.975	2.09%	2009	0.979899
2010	1.00	2.04%	0.995	2.05%	2010	1.000000
2011	1.02	2.00%	1.015	2.01%	2011	1.020101
2012	1.04	1.96%	1.035	1.97%	2012	1.040201
2013	1.06	1.92%	1.055	1.93%	2013	1.060302
2014	1.08	1.89%	1.075	1.90%	2014	1.080402
2015	1.11	2.78%	1.103	2.60%	2015	1.108543
2016	1.13	1.80%	1.125	1.99%	2016	1.130653
2017	1.15	1.77%	1.145	1.78%	2017	1.150754
2018	1.17	1.74%	1.165	1.75%	2018	1.170854
2019	1.20	2.56%	1.193	2.40%	2019	1.198995
2020	1.22	1.67%	1.215	1.84%	2020	1.221106
2021	1.25	2.46%	1.243	2.30%	2021	1.249246
2022	1.27	1.60%	1.265	1.77%	2022	1.271357
2023	1.29	1.57%	1.285	1.58%	2023	1.291457
2024	1.32	2.33%	1.313	2.18%	2024	1.319598
2025	1.34	1.52%	1.335	1.68%	2025	1.341709
2026	1.37	2.24%	1.363	2.10%	2026	1.369849
2027	1.39	1.46%	1.385	1.61%	2027	1.391960
2028	1.42	2.16%	1.413	2.02%	2028	1.420101
2029	1.44	1.41%	1.435	1.56%	2029	1.442211
2030	1.47	2.08%	1.463	1.95%	2030	1.470352
2031	1.50	2.04%	1.493	2.05%	2031	1.500503
2032	1.52	1.33%	1.515	1.47%	2032	1.522613
2033	1.55	1.97%	1.543	1.85%	2033	1.550754
2034	1.58	1.94%	1.573	1.94%	2034	1.580905
2035	1.60	1.27%	1.595	1.40%	2035	1.603015
2036	1.63	1.87%	1.623	1.76%	2036	1.631156
2037	1.66	1.84%	1.653	1.85%	2037	1.661307
2038	1.69	1.81%	1.683	1.81%	2038	1.691457

1/ Global Insight, The U.S. Economy: The 30-Year Focus, August 2008, Base Case Scenario.

2/ Fiscal Year Cumulative Price Deflator escalates to midyear dollars. The first year, 2009, is determined as follows: 1.011 = [(2.159/100)*.5] + 1. An example of subsequent year cumulative growth such as in 2010 is found as: 1.032 = [1+ (2.057/100)]*1.011 (Official Agency Forecast Footnote - Will Revise Later)

'3/ Index restated to arrive at FY 2010 value = 1.00000.

Section 7(b)(2) Rate Test Study and Documentation
Alternative Conservation Expense Deferral / Financing Periods
WP-10 Initial Rate Proposal

SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 1 - Resource Stack Selected Resources - Resource Composition:

a) - Conservation Resources - Composition and Timing of Costs - Costs That are Constant Across All Alternatives [1] :

Total FY 2010-FY 2015	FY 2010	FY 2011-2015	FY 2016-2029
Total Expense Costs	Expense Costs	Expense Costs	Expense Costs
$774,228,800	$325,062,100	$449,166,700	None
Total Capitalized Costs	Capitalized Costs	Capitalized Costs	Expense Costs
$394,638,700	$165,466,200	$229,172,500	None
Total Investment Costs Excluding Interest			
$1,168,867,500	$490,528,300	$678,339,200	$0

Total FY 2010-FY 2029	FY 2010	FY 2011-2015	FY 2016-2029
Total Interest Expense Capitalized Costs /1	Interest on Capitalized Costs	Interest on Capitalized Costs	Interest on Capitalized Costs
$159,215,300	$7,561,807	$61,371,476	$90,282,017

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Section 7(b)(2) Rate Test Study and Documentation
Alternative Conservation Expense Deferral / Financing Periods
WP-10 Initial Rate Proposal

SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 1 - Resource Stack Selected Resources - Resource Composition:

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	Totals FY 2010-2015
b) - Conservation Resources Selected from the Resource Stack:							
Number of years of conservation investments:	(9)	(1)	(1)	(1)	(1)	(1)	(14)
Conservation MWs-	255.0	38.8	38.8	38.8	38.8	34.6	444.8
Selected from the Resource Stack:	73.0%						82.5%
c) - Non-Conservation Resources Selected from the Resource Stack:							
Idaho Falls Hydro Resource	18.5						18.5
Boardman Coal Plant	49.7						49.7
Cowlitz Falls Hydro Resource	26.0						26.0
	94.2						94.2
	27.0%						17.5%
Selected Resource MW Amounts	349.2	38.8	38.8	38.8	38.8	34.6	539.0

Note 1 - Conservation resource costs in this table have been adjusted for inflation to reflect the purchasing power costs of the year the resource is selected from the resource stack. This financing analysis assumes that financing origination of capitalized investments and conservation investments that have been deferred occurs on the first day of the fiscal year.

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Section 7(b)(2) Rate Test Study and Documentation
Alternative Conservation Expense Deferral / Financing Periods
WP-10 Initial Rate Proposal

SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 2 - Financing Costs Associated with Deferring Conservation Expensed Costs:

(3)		(4)	(5)	(6)	(7)	(8)	(9)
				(4) + (5)		(6) + (7)	(8) / (3)
Total Conservation Expense Costs Excluding Interest **774,228,800**	Interest Rate	Years 1-2 Rate Period Interest Paid - FY 2010-2011	Years 3-6 of Rate Test Period Interest Paid FY 2012-2015	Total Rate Test Period Interest Paid FY 2010-2015	Years Outside of Rate Test Period Interest Paid FY 2016-2029	Total Interest Paid FY 2010-2029	Percent of Total Interest to Deferred Expenses FY 2010-2029
Alternative 1 - Expense in the							
year incurred, no deferral	N/A	0	0	0	0	0	0.00%
Alternative 2 - Deferral -	3.70%	$24,347,516	$39,645,531	$63,993,047	$8,923,612	$72,916,659	9.42%
financing over 4-years		33.39%	54.37%	87.76%	12.24%	100.00%	
Alternative 3 - Deferral -	3.79%	$25,569,806	$49,947,739	$75,517,545	$14,694,068	$90,211,613	11.65%
financing over 5-years		28.34%	55.37%	83.71%	16.29%	100.00%	
Alternative 4 - Deferral -	3.88%	$26,608,174	$59,832,289	$86,440,463	$22,032,077	$108,472,540	14.01%
financing over 6-years		24.53%	55.16%	79.69%	20.31%	100.00%	
Alternative 5 - Deferral -	3.97%	$27,541,446	$67,598,359	$95,139,805	$32,588,312	$127,728,117	16.50%
financing over 7-years		21.56%	52.92%	74.49%	25.51%	100.00%	
Alternative 6 - Deferral -	4.57%	$32,875,410	$101,511,878	$134,387,288	$177,965,168	$312,352,456	40.34%
financing over 15-years		10.53%	32.50%	43.02%	56.98%	100.00%	

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Section 7(b)(2) Rate Test Study and Documentation
Alternative Conservation Expense Deferral / Financing Periods
WP-10 Initial Rate Proposal

Factor 3 - Cost Recovery Considerations:

	Weighted Average Cost Recovery Period			
	($ 000) Conservation Investment Cost	Recovery Period Years	Weighted Average Recovery Period - Years	Percent of Total Costs Recovered During the Rate Test Period
"Mock" Program Case				
- Accounting and Financing Treatment				
Capital Expenditures	$261,799.9	5	1.64	
Expensed Expenditures	$534,505.9	1	0.67	
Total Cost	**$796,305.8**		**2.31**	**87.42%**
Alternative 1 - Expense				
in the year incurred, no deferral				
Capital Expenditures	$394,638.7	15	5.06	
Expensed Expenditures	$774,228.8	1	0.66	
Total Cost	**$1,168,867.5**		**5.72**	**73.79%**
Alternative 2 - Deferral -				
financing over 4-years				
Capital Expenditures	$394,638.7	15	5.06	
Expensed Expenditures	$774,228.8	4	2.65	
Total Cost	**$1,168,867.5**		**7.71**	**61.51%**
Alternative 3 - Deferral -				
financing over 5-years				
Capital Expenditures	$394,638.7	15	5.06	
Expensed Expenditures	$774,228.8	5	3.31	
Total Cost	**$1,168,867.5**		**8.37**	**57.43%**
Alternative 4 - Deferral -				
financing over 6-years				
Capital Expenditures	$394,638.7	15	5.06	
Expensed Expenditures	$774,228.8	6	3.97	
Total Cost	**$1,168,867.5**		**9.03**	**53.37%**
Alternative 5 - Deferral -				
financing over 7-years				
Capital Expenditures	$394,638.7	15	5.06	
Expensed Expenditures	$774,228.8	7	4.64	
Total Cost	**$1,168,867.5**		**9.70**	**46.03%**
Alternative 6 - Deferral -				
financing over 15-years				
Capital Expenditures	$394,638.7	15	5.06	
Expensed Expenditures	$774,228.8	15	9.94	
Total Cost	**$1,168,867.5**		**15.00**	**22.27%**

	A / B	D	E	F	G	H	I	J
1	**Section 7(b)(2) Rate Test Study and Documentation**							
2	**Alternative Conservation Expense Deferral / Financing Periods**							
3	**WP-10 Initial Rate Proposal**							
5	**Factor 4 - Cost Comparability Between the Program Case and the 7(b)(2) Case:**							
7	($ 000)							
9		**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**	**AVERAGES**
10	**Program Case Conservation Expense Costs:**							
11	Staffing, Indirect, General & Administrative	22,546.0	23,263.0	24,482.0	25,257.0	26,012.0	26,946.0	
12	Market Transformation Funding	12,000.0	12,000.0	12,000.0	12,000.0	12,000.0	12,000.0	
13	Expense Agreements & Grants	5,000.0	5,000.0	6,000.0	6,000.0	6,000.0	6,000.0	
14	Conservation Rate Credit	32,000.0	32,000.0	32,000.0	32,000.0	32,000.0	32,000.0	
15	Program Support & Evaluation Costs	14,000.0	14,000.0	15,000.0	15,000.0	15,000.0	15,000.0	
16	**Sub Total Expense Costs - 7(b)(2) Amounts[1]**	85,546.0	86,263.0	89,482.0	90,257.0	91,012.0	91,946.0	**89,084.3**
18	Federal Reimbursable Program (EE Development)	20,500.0	20,500.0	22,000.0	22,000.0	22,000.0	22,000.0	
19	Demand Management Supply Technology	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	1,600.0	
20	Legacy Conservation - Prior Year Efforts	1,988.0	1,622.0	999.0	1,311.0	717.0	717.0	
21	Other Offsetting Credits	(2,241.0)	(2,162.0)	(2,184.0)	(2,203.0)	(2,220.0)	(2,369.0)	
23	**Total Direct Conservation Expenses - Program Case - (A)**	107,393.0	107,823.0	111,897.0	112,965.0	113,109.0	113,894.0	**111,180.2**
24	**Program Case Offsetting Revenue Credits**	(20,500.0)	(20,500.0)	(22,000.0)	(22,000.0)	(22,000.0)	(22,000.0)	
25	**Similar Program Case Expense Level Comparison - (D)**	86,893.0	87,323.0	89,897.0	90,965.0	91,109.0	91,894.0	**89,680.2**
27	**Program Case Capital Costs, Interest Expense:**							
28	Current Year's Capitalized Conservation Amortization	3,230.0	3,910.0	3,910.0	3,910.0	3,910.0	3,910.0	
29	Prior Year's BPA Capitalized Conservation Amortization	47,045.4	51,655.4	42,421.0	45,674.0	46,570.0	44,159.0	
30	Prior Year's Other Entities Debt Service Requirements	5,078.6	4,923.6	4,923.0	4,917.0	4,911.0	305.0	
31	Net Interest Expense - Allocated to Conservation	13,754.0	12,551.0	11,062.0	10,777.0	9,829.0	8,948.0	
32	**Total Program Case Capital Costs, Interest Expense - (B)**	69,108.0	73,040.0	62,316.0	65,278.0	65,220.0	57,322.0	**65,380.7**
34	**Program Case MRNR, PNRR, and Billing Credits:**							
35	MRNR - Allocated to Conservation	10,237.9	311.0	0.0	2,370.0	2,161.0	1,967.0	
36	PNRR - Allocated to Conservation	3,597.1	3,508.0	0.0	0.0	0.0	0.0	
37	Billing Credits	7,383.0	7,469.0	5,873.0	5,685.0	5,750.0	5,796.0	
38	**Total Program Case MRNR, PNRR, and Billing Credits - (C)**	21,218.0	11,288.0	5,873.0	8,055.0	7,911.0	7,763.0	**10,351.3**
40	**CONSERVATION TOTAL - LINE 18 COSA (E) = (A) + (B) + (C)**	197,719.0	192,151.0	180,086.0	186,298.0	186,240.0	178,979.0	**186,912.2**
42	**Similar Program Case Comparison Amounts (F) = (D) + (B)**	**156,001.0**	**160,363.0**	**152,213.0**	**156,243.0**	**156,329.0**	**149,216.0**	**155,060.8**
44	**7(b)(2) Case Debt Service Requirements - Principal and Interest ($ 000) -**							
45	**Expense Deferral and Financing Over 5-Years (Alternative 3)**							
47	**Capital Costs - Debt Service Requirements**	15,481.5	19,589.4	23,867.5	28,321.1	32,957.4	36,923.6	
48	**Expense Costs - Debt Service Requirements**	72,587.7	91,525.7	111,048.1	131,202.8	152,004.2	100,300.5	
49	**7(b)(2) CASE TOTAL DEBT SERVICE REQUIREMENTS - (G)**	**88,069.2**	**111,115.1**	**134,915.6**	**159,523.9**	**184,961.6**	**137,224.1**	**135,968.3**
50								
51	**INCREASE - (DECREASE) IN PROGRAM CASE OVER 7(B)(2) CASE (F - G) :**	**67,931.8**	**49,247.9**	**17,297.4**	**(3,280.9)**	**(28,632.6)**	**11,991.9**	**19,092.6**
53	Note 1 - See Page D - 20 for a detailed description of conservation costs for FY 2008 -FY 2015.							
55								
57								
58								

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Alternative Conservation Expense Deferral / Financing Periods
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SUMMARY ANALYSIS - ACCOUNTING / FINANCING TREATMENT OF EXPENSED CONSERVATION COSTS

Factor 5 - 7(b)(2) Case - Rate Impacts:

	FY 2010-2011 Average Rates		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Alternative 1 - Expense in		7b2 PF Rate	29.71	26.27	23.21	25.86	25.28	27.73
the year incurred,		7b2 PF Rate Loads	67526	67743	69811	70156	71525	72235
no deferral	27.99	Revenues	2,006,204	1,779,602	1,620,310	1,814,237	1,808,156	2,003,086
Alternative 2 - Deferral -		7b2 PF Rate	26.21	26.67	23.91	26.86	25.33	27.81
financing over 4-years		7b2 PF Rate Loads	67526	67743	69811	70156	71525	72235
	26.44	Revenues	1,769,862	1,806,699	1,669,177	1,884,393	1,811,732	2,008,865
Alternative 3 - Deferral -		7b2 PF Rate	25.97	26.36	23.55	26.44	26.10	27.82
financing over 5-years		7b2 PF Rate Loads	67526	67743	69811	70156	71525	72235
	26.17	Revenues	1,753,656	1,785,698	1,644,045	1,854,927	1,866,806	2,009,587
Alternative 4 - Deferral -		7b2 PF Rate	25.81	26.16	23.32	26.16	25.78	28.47
financing over 6-years		7b2 PF Rate Loads	67526	67743	69811	70156	71525	72235
	25.99	Revenues	1,742,851	1,772,150	1,627,989	1,835,283	1,843,918	2,056,540
Alternative 5 - Deferral -		7b2 PF Rate	25.70	26.02	23.15	25.97	25.56	28.22
financing over 7-years		7b2 PF Rate Loads	67526	67743	69811	70156	71525	72235
	25.86	Revenues	1,735,423	1,762,666	1,616,121	1,821,954	1,828,183	2,038,481
Alternative 6 - Deferral -		7b2 PF Rate	25.35	25.58	22.63	25.36	24.86	27.44
financing over 15-years		7b2 PF Rate Loads	67526	67743	69811	70156	71525	72235
	25.47	Revenues	1,711,789	1,732,859	1,579,819	1,779,159	1,778,115	1,982,138

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Alternative Conservation Expense Accounting and Financing Treatments

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"Mock Program Case Treatment of 7(b)(2) Adjusted Conservation Amounts"

	Inflation Adjustment	Capitalized Conservation Interest Rate 5 - Year Maturity	"Expensed" Conservation Expenditures Are Expensed in the Year Incurred
FY 2010	1.000000		
FY 2011	1.020232		
FY 2012	1.041582		
FY 2013	1.062788		
FY 2014	1.084313	0.0535	
FY 2015	1.106094		

Schedule of 7 (b)(2) Case Conservation Investments - Using Program Case Accounting Methods

Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt Service Whole Dollars
#1 2010 Conservation - 2010$$	31.2	85,546.0	32,300.0	117,846.0	
Capitalized Costs - Debt Service Requirements					7,532,812.64
Expensed Costs /Deferral Debt Service Requirements					85,546,000.00
2011 Conservation - 2010$$	34.6	84,552.3	38,324.6	122,876.9	
#2 2011 Conservation - 2011$$		86,263.0	39,100.0	125,363.0	
Capitalized Costs - Debt Service Requirements					9,118,667.93
Expensed Costs /Deferral Debt Service Requirements					86,263,000.00
2012 Conservation - 2010$$	38.8	85,909.7	45,699.7	131,609.5	
#3 2012 Conservation - 2012$$		89,482.0	47,600.0	137,082.0	
Capitalized Costs - Debt Service Requirements					11,100,987.04
Expensed Costs /Deferral Debt Service Requirements					89,482,000.00
2013 Conservation - 2010$$	38.8	84,924.7	44,787.8	129,712.6	
#4 2013 Conservation - 2013$$		90,257.0	47,599.9	137,856.9	
Capitalized Costs - Debt Service Requirements					11,100,963.72
Expensed Costs /Deferral Debt Service Requirements					90,257,000.00
2014 Conservation - 2010$$	38.8	83,935.2	43,898.8	127,833.9	
#5 2014 Conservation - 2014$$		91,012.0	47,600.0	138,612.0	
Capitalized Costs - Debt Service Requirements					11,100,987.04
Expensed Costs /Deferral Debt Service Requirements					91,012,000.00
2015 Conservation - 2010$$	38.8	83,126.7	43,034.3	126,161.1	
#6 2015 Conservation - 2015$$		91,945.9	47,600.0	139,545.9	
Capitalized Costs - Debt Service Requirements					11,100,987.04
Expensed Costs /Deferral Debt Service Requirements					91,945,900.00

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		261,799.9	54,578.6	316,378.5
TOTAL Expense Costs - Debt Serv. Req. = TEC	534,505.9		0.0	534,505.9
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	534,505.9	261,799.9	54,578.6	850,884.4
				850,884.4

Principal Expense Costs	534,505.9
Interest Paid Expensed Costs	0.0
Principal Capital Costs	261,799.9
Interest Paid Capital Costs	54,578.6
Totals	**850,884.4**

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"Mock Program Case Treatment of 7(b)(2) Adjusted Conservation Amounts"

Schedule of 7 (b)(2) Case Conservation Investments - Using Program Case Accounting Methods

Debt Service Requirements - Principal and Interest ($ 000)

		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
2010 Conservation - 2010$$											
Capitalized Costs - Debt Service		7,532.8	7,532.8	7,532.8	7,532.8	7,532.8	0.0	0.0	0.0	0.0	0.0
Expensed Expenditures		85,546.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011 Conservation - 2011$$											
Capitalized Costs - Debt Service		0.0	9,118.7	9,118.7	9,118.7	9,118.7	9,118.7	0.0	0.0	0.0	0.0
Expensed Expenditures		0.0	86,263.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012 Conservation - 2012$$											
Capitalized Costs - Debt Service		0.0	0.0	11,101.0	11,101.0	11,101.0	11,101.0	11,101.0	0.0	0.0	0.0
Expensed Expenditures		0.0	0.0	89,482.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013 Conservation - 2013$$											
Capitalized Costs - Debt Service		0.0	0.0	0.0	11,101.0	11,101.0	11,101.0	11,101.0	11,101.0	0.0	0.0
Expensed Expenditures		0.0	0.0	0.0	90,257.0	0.0	0.0	0.0	0.0	0.0	0.0
2014 Conservation - 2014$$											
Capitalized Costs - Debt Service		0.0	0.0	0.0	0.0	11,101.0	11,101.0	11,101.0	11,101.0	11,101.0	11,101.0
Expensed Expenditures		0.0	0.0	0.0	0.0	91,012.0	0.0	0.0	0.0	0.0	0.0
2015 Conservation - 2015$$											
Capitalized Costs - Debt Service		0.0	0.0	0.0	0.0	0.0	11,101.0	11,101.0	11,101.0	11,101.0	11,101.0
Expensed Expenditures		0.0	0.0	0.0	0.0	0.0	91,945.9	0.0	0.0	0.0	0.0
ANNUAL TOTALS											
Capital Costs - Debt Service Requirements		7,532.8	16,651.5	27,752.5	38,853.5	49,954.5	53,522.7	44,404.0	33,303.0	22,202.0	22,202.0
Expense Costs - Expensed in the Year Incurred		85,546.0	86,263.0	89,482.0	90,257.0	91,012.0	91,945.9	0.0	0.0	0.0	0.0
	850,884.4	93,078.8	102,914.5	117,234.5	129,110.5	140,966.5	145,468.6	44,404.0	33,303.0	22,202.0	22,202.0

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"Mock Program Case Treatment of 7(b)(2) Adjusted Conservation Amounts"

Amortization of Principal - Conservation Capital Expend. Bond Sinking Fund Payments
Schedule of Conservation First Year Expensed Amounts
(whole dollars)

	Cumulative Totals	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
2010 Conservation - 2010$$											
Capital Expenditures - Amortization of Principal	32,300,000	5,804,763	6,115,318	6,442,487	6,787,160	7,150,272	0	0	0	0	0
Expensed Expenditures	85,546,000	85,546,000	0	0	0	0	0	0	0	0	0
2011 Conservation - 2011$$											
Capital Expenditures - Amortization of Principal	39,100,000	0	7,026,818	7,402,753	7,798,800	8,216,036	8,655,593	0	0	0	0
Expensed Expenditures	86,263,000	0	86,263,000	0	0	0	0	0	0	0	0
2012 Conservation - 2012$$											
Capital Expenditures - Amortization of Principal	47,600,000	0	0	8,554,387	9,012,047	9,494,191	10,002,130	10,537,245			
Expensed Expenditures	89,482,000	0	0	89,482,000	0	0	0	0	0	0	0
2013 Conservation - 2013$$											
Capital Expenditures - Amortization of Principal	47,599,900	0	0	0	8,554,369	9,012,028	9,494,172	10,002,110	10,537,221	0	0
Expensed Expenditures	90,257,000	0	0	0	90,257,000	0	0	0	0	0	0
2014 Conservation - 2014$$											
Capital Expenditures - Amortization of Principal	47,600,000	0	0	0	0	8,554,387	9,012,047	9,494,191	10,002,130	10,537,245	
Expensed Expenditures	91,012,000	0	0	0	0	91,012,000	0	0	0	0	0
2015 Conservation - 2015$$											
Capital Expenditures - Amortization of Principal	47,600,000	0	0	0	0	0	8,554,387	9,012,047	9,494,191	10,002,130	10,537,245
Expensed Expenditures	91,945,900	0	0	0	0	0	91,945,900	0	0	0	0
TOTALS AMORTIZATION OF PRINCIPAL	261,799,900	5,804,763	13,142,136	22,399,627	32,152,376	42,426,914	45,718,329	39,045,593	30,033,542	20,539,375	10,537,245
	261,799,900										
TOTALS EXPENSED CONSERVATION	534,505,900	85,546,000	86,263,000	89,482,000	90,257,000	91,012,000	91,945,900	0	0	0	0
	534,505,900										
TOTAL CONSERVATION PRINCIPAL AND EXPENSE COSTS	796,305,800	91,350,763	99,405,136	111,881,627	122,409,376	133,438,914	137,664,229	39,045,593	30,033,542	20,539,375	10,537,245
PERCENTAGE OF TOTAL PRINCIPAL AND EXPENSE COSTS PAID		11.47%	12.48%	14.05%	15.37%	16.76%	17.29%	4.90%	3.77%	2.58%	1.32%
CUMULATIVE PRINCIPAL AND EXPENSE COSTS PAID		11.47%	23.95%	38.00%	53.37%	70.13%	$\boxed{87.42\%}$	92.32%	96.09%	98.67%	99.99%
PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD		87.42%									

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Alternative Conservation Expense Accounting and Financing Treatments
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"Mock Program Case Treatment of 7(b)(2) Adjusted Conservation Amounts"

Amortization Schedules - Annual Capitalized Conservation Investments

#1 2010 Conservation - 2010$$

	Fiscal Year	Payment Amount (7,532,813)	0.0535 Interest	Principal Reduction	Balance
Conservation Capital Expenditures Amortization Schedule		beginning balance			32,300,000
	2010	7,532,813	1,728,050	5,804,763	26,495,237
	2011	7,532,813	1,417,495	6,115,318	20,379,919
	2012	7,532,813	1,090,326	6,442,487	13,937,432
	2013	7,532,813	745,653	6,787,160	7,150,272
	2014	7,532,812	382,540	7,150,272	0
		Totals	5,364,064	32,300,000	0

#2 2011 Conservation - 2011$$

	Fiscal Year	Payment Amount (9,118,668)	0.0535 Interest	Principal Reduction	Balance
Conservation Capital Expenditures Amortization Schedule		beginning balance			39,100,000
	2011	9,118,668	2,091,850	7,026,818	32,073,182
	2012	9,118,668	1,715,915	7,402,753	24,670,429
	2013	9,118,668	1,319,868	7,798,800	16,871,629
	2014	9,118,668	902,632	8,216,036	8,655,593
	2015	9,118,667	463,074	8,655,593	0
		Totals	6,493,339	39,100,000	0

#3 2012 Conservation - 2012$$

	Fiscal Year	Payment Amount (11,100,987)	0.0535 Interest	Principal Reduction	Balance
Conservation Capital Expenditures Amortization Schedule		beginning balance			47,600,000
	2012	11,100,987	2,546,600	8,554,387	39,045,613
	2013	11,100,987	2,088,940	9,012,047	30,033,566
	2014	11,100,987	1,606,796	9,494,191	20,539,375
	2015	11,100,987	1,098,857	10,002,130	10,537,245
	2016	11,100,988	563,743	10,537,245	0
		Totals	7,904,936	47,600,000	0

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Alternative Conservation Expense Accounting and Financing Treatments
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"Mock Program Case Treatment of 7(b)(2) Adjusted Conservation Amounts"

Amortization Schedules - Annual Capitalized Conservation Investments

#4 2013 Conservation - 2013$$

		11,100,964			
Conservation	Fiscal	Payment	0.0535	Principal	
Capital	Year	Amount	Interest	Reduction	Balance
Expenditures					
Amortization		beginning balance			47,599,900
Schedule	2013	11,100,964	2,546,595	8,554,369	39,045,531
	2014	11,100,964	2,088,936	9,012,028	30,033,503
	2015	11,100,964	1,606,792	9,494,172	20,539,331
	2016	11,100,964	1,098,854	10,002,110	10,537,221
	2017	11,100,962	563,741	10,537,221	0
		Totals	7,904,918	47,599,900	0

#5 2014 Conservation - 2014$$

		11,100,987			
Conservation	Fiscal	Payment	0.0535	Principal	
Capital	Year	Amount	Interest	Reduction	Balance
Expenditures					
Amortization		beginning balance			47,600,000
Schedule	2014	11,100,987	2,546,600	8,554,387	39,045,613
	2015	11,100,987	2,088,940	9,012,047	30,033,566
	2016	11,100,987	1,606,796	9,494,191	20,539,375
	2017	11,100,987	1,098,857	10,002,130	10,537,245
	2018	11,100,988	563,743	10,537,245	0
		Totals	7,904,936	47,600,000	0

#6 2015 Conservation - 2015$$

		11,100,987			
Conservation	Fiscal	Payment	0.0535	Principal	
Capital	Year	Amount	Interest	Reduction	Balance
Expenditures					
Amortization		beginning balance			47,600,000
Schedule	2015	11,100,987	2,546,600	8,554,387	39,045,613
	2016	11,100,987	2,088,940	9,012,047	30,033,566
	2017	11,100,987	1,606,796	9,494,191	20,539,375
	2018	11,100,987	1,098,857	10,002,130	10,537,245
	2019	11,100,988	563,743	10,537,245	0
		Totals	7,904,936	47,600,000	0

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Scenario = Capitalized costs are amortized and financed over 15 years,
Expensed costs are expensed in the year incurred (1st year)

ALTERNATIVE - 1

	Inflation Adjustment	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	0.0457	4	0.0370
FY 2011	1.020232		5	0.0379
FY 2012	1.041582		6	0.0388
FY 2013	1.062788		7	0.0397
FY 2014	1.084313		15	0.0457
FY 2015	1.106094			

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected						
1	2004 Conservation - 2010$$	31.4	18,502.0	22,723.7	41,225.7	
	Capitalized Costs - Debt Service Requirements					$2,126,085.25
	Expensed Costs /Deferral Debt Service Requirements					18,502,000.00
2	2001 Conservation - 2010$$	18.7	24,855.2	71.2	24,926.4	
	Capitalized Costs - Debt Service Requirements					$6,661.65
	Expensed Costs /Deferral Debt Service Requirements					24,855,200.00
4	2006 Conservation - 2010$$	30.2	30,761.1	16,438.0	47,199.1	
	Capitalized Costs - Debt Service Requirements					1,537,979.70
	Expensed Costs /Deferral Debt Service Requirements					30,761,100.00
5	2007 Conservation - 2010$$	28.5	41,499.7	11,453.5	52,953.2	
	Capitalized Costs - Debt Service Requirements					1,071,617.62
	Expensed Costs /Deferral Debt Service Requirements					41,499,700.00
6	2003 Conservation - 2010$$	25.2	20,758.3	27,500.1	48,258.4	
	Capitalized Costs - Debt Service Requirements					2,572,976.98
	Expensed Costs /Deferral Debt Service Requirements					20,758,300.00
7	2005 Conservation - 2010$$	20.0	25,443.0	16,719.5	42,162.5	
	Capitalized Costs - Debt Service Requirements					1,564,317.53
	Expensed Costs /Deferral Debt Service Requirements					25,443,000.00
8	2002 Conservation - 2010$$	26.1	21,005.4	34,586.6	55,592.0	
	Capitalized Costs - Debt Service Requirements					3,236,007.34
	Expensed Costs /Deferral Debt Service Requirements					21,005,400.00
9	2008 Conservation - 2010$$	34.8	65,070.9	8,214.0	73,284.9	
	Capitalized Costs - Debt Service Requirements					768,522.04
	Expensed Costs /Deferral Debt Service Requirements					65,070,900.00
12	2009 Conservation - 2010$$	40.1	77,166.5	27,759.6	104,926.1	
	Capitalized Costs - Debt Service Requirements					2,597,256.44
	Expensed Costs /Deferral Debt Service Requirements					77,166,500.00

**Scenario = Capitalized costs are amortized and financed over 15 years,
Expensed costs are expensed in the year incurred (1st year)**

ALTERNATIVE - 1

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1
		18,502.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	**2001 Conservation - 2010$$**										
		6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
		24,855.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2006 Conservation - 2010$$**										
		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0
		30,761.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	**2007 Conservation - 2010$$**										
		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6
		41,499.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2003 Conservation - 2010$$**										
		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0
		20,758.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**2005 Conservation - 2010$$**										
		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3
		25,443.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**2002 Conservation - 2010$$**										
		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0
		21,005.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**2008 Conservation - 2010$$**										
		768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5
		65,070.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3
		77,166.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1					
		0.0	0.0	0.0	0.0	0.0					
2	**2001 Conservation - 2010$$**										
		6.7	6.7	6.7	6.7	6.7					
		0.0	0.0	0.0	0.0	0.0					
4	**2006 Conservation - 2010$$**										
		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0					
		0.0	0.0	0.0	0.0	0.0					
5	**2007 Conservation - 2010$$**										
		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6					
		0.0	0.0	0.0	0.0	0.0					
6	**2003 Conservation - 2010$$**										
		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0					
		0.0	0.0	0.0	0.0	0.0					
7	**2005 Conservation - 2010$$**										
		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3					
		0.0	0.0	0.0	0.0	0.0					
8	**2002 Conservation - 2010$$**										
		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0					
		0.0	0.0	0.0	0.0	0.0					
9	**2008 Conservation - 2010$$**										
		768.5	768.5	768.5	768.5	768.5					
		0.0	0.0	0.0	0.0	0.0					
12	**2009 Conservation - 2010$$**										
		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3					
		0.0	0.0	0.0	0.0	0.0					

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$	38.8	83,126.7	43,034.3	126,161.1	
13	**2015 Conservation - 2011$$**		84,808.5	43,905.0	128,713.5	
	Capitalized Costs - Debt Service Requirements					4,107,859.76
	Expensed Costs /Deferral Debt Service Requirements					84,808,500.00
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$	38.8	83,935.2	43,898.8	127,833.9	
14	**2014 Conservation - 2012$$**		87,425.4	45,724.2	133,149.6	
	Capitalized Costs - Debt Service Requirements					4,278,068.59
	Expensed Costs /Deferral Debt Service Requirements					87,425,400.00
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$	38.8	84,924.7	44,787.8	129,712.6	
15	**2013 Conservation - 2013$$**		90,257.0	47,599.9	137,856.9	
	Capitalized Costs - Debt Service Requirements					4,453,563.69
	Expensed Costs /Deferral Debt Service Requirements					90,257,000.00
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$	38.8	85,909.7	45,699.7	131,609.5	
16	**2012 Conservation - 2014$$**		93,153.0	49,552.8	142,705.8	
	Capitalized Costs - Debt Service Requirements					4,636,281.82
	Expensed Costs /Deferral Debt Service Requirements					93,153,000.00
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$	34.6	84,552.3	38,324.6	122,876.9	
17	**2011 Conservation - 2015$$**		93,522.8	42,390.6	135,913.4	
	Capitalized Costs - Debt Service Requirements					3,966,168.77
	Expensed Costs /Deferral Debt Service Requirements					93,522,800.00

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		394,638.7	159,215.3	553,854.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	774,228.8		0.0	774,228.8
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	774,228.8	394,638.7	159,215.3	1,328,082.8

Principal Expense Costs	774,228.8
Interest Paid Expensed Costs	0.0
Principal Capital Costs	394,638.7
Interest Paid Capital Costs	159,215.3
Totals	1,328,082.8

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
		1	2	3	4	5	6	7	8	9	10
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
		0.0	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9
		0.0	84,808.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
		0.0	0.0	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1
		0.0	0.0	87,425.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
		0.0	0.0	0.0	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6
		0.0	0.0	0.0	90,257.0	0.0	0.0	0.0	0.0	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
		0.0	0.0	0.0	0.0	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3
		0.0	0.0	0.0	0.0	93,153.0	0.0	0.0	0.0	0.0	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
		0.0	0.0	0.0	0.0	0.0	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
		0.0	0.0	0.0	0.0	0.0	93,522.8	0.0	0.0	0.0	0.0
TCC		15,481.5	19,589.4	23,867.5	28,321.1	32,957.4	36,923.6	36,923.6	36,923.6	36,923.6	36,923.6
TEC		325,062.1	84,808.5	87,425.4	90,257.0	93,153.0	93,522.8	0.0	0.0	0.0	0.0
TDSR		340,543.6	104,397.9	111,292.9	118,578.1	126,110.4	130,446.4	36,923.6	36,923.6	36,923.6	36,923.6

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
		11	12	13	14	15	16	17	18	19	20
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
		4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9				
		0.0	0.0	0.0	0.0	0.0	0.0				
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
		4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1			
		0.0	0.0	0.0	0.0	0.0	0.0	0.0			
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
		4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6		
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
		4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
		3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2
TEC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010 Conservation Resources Selected										
FY 2010 Conservation (9) Res. Selected - Total MW =		255								
1	**2004 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	22,723,700	1,087,612	1,137,316	1,189,291	1,243,642	1,300,476	1,359,908	1,422,056	1,487,044
	Expense Expenditures - Amort. of Principal	18,502,000	18,502,000	0	0	0	0	0	0	0
2	**2001 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	71,200	3,408	3,564	3,727	3,897	4,075	4,261	4,456	4,660
	Expense Expenditures - Amort. of Principal	24,855,200	24,855,200	0	0	0	0	0	0	0
4	**2006 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,438,000	786,763	822,718	860,317	899,633	940,746	983,738	1,028,695	1,075,707
	Expense Expenditures - Amort. of Principal	30,761,100	30,761,100	0	0	0	0	0	0	0
5	**2007 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	11,453,500	548,193	573,245	599,443	626,837	655,484	685,439	716,764	749,520
	Expense Expenditures - Amort. of Principal	41,499,700	41,499,700	0	0	0	0	0	0	0
6	**2003 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,500,100	1,316,222	1,376,374	1,439,274	1,505,049	1,573,830	1,645,754	1,720,965	1,799,613
	Expense Expenditures - Amort. of Principal	20,758,300	20,758,300	0	0	0	0	0	0	0
7	**2005 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,719,500	800,237	836,808	875,050	915,040	956,857	1,000,585	1,046,312	1,094,128
	Expense Expenditures - Amort. of Principal	25,443,000	25,443,000	0	0	0	0	0	0	0
8	**2002 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	34,586,600	1,655,399	1,731,051	1,810,160	1,892,884	1,979,389	2,069,847	2,164,439	2,263,354
	Expense Expenditures - Amort. of Principal	21,005,400	21,005,400	0	0	0	0	0	0	0
9	**2008 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	8,214,000	393,142	411,109	429,896	449,543	470,087	491,570	514,035	537,526
	Expense Expenditures - Amort. of Principal	65,070,900	65,070,900	0	0	0	0	0	0	0
12	**2009 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,759,600	1,328,642	1,389,361	1,452,855	1,519,250	1,588,680	1,661,283	1,737,204	1,816,594
	Expense Expenditures - Amort. of Principal	77,166,500	77,166,500	0	0	0	0	0	0	0

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected													
FY 2010 Conservation (9) Res. Selected - Total MW =													
1	2004 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	1,555,002	1,626,065	1,700,376	1,778,084	1,859,342	1,944,314	2,033,172					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
2	2001 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	4,873	5,095	5,328	5,572	5,826	6,093	6,365					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
4	2006 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	1,124,866	1,176,273	1,230,029	1,286,241	1,345,022	1,406,490	1,470,762					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
5	2007 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	783,773	819,592	857,047	896,214	937,171	980,000	1,024,778					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
6	2003 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	1,881,855	1,967,856	2,057,787	2,151,828	2,250,166	2,352,999	2,460,528					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
7	2005 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	1,144,130	1,196,417	1,251,093	1,308,268	1,368,056	1,430,576	1,495,943					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
8	2002 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	2,366,789	2,474,952	2,588,057	2,706,331	2,830,011	2,959,342	3,094,595					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
9	2008 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	562,091	587,778	614,640	642,729	672,102	702,817	734,935					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
12	2009 Conservation - 2010$$												
	Capital Expenditures - Amort. of Principal	1,899,612	1,986,424	2,077,204	2,172,132	2,271,399	2,375,202	2,483,758					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2011	**Conservation Resources Selected**									
13	**2015 Conservation - 2011$$**									
	Capital Expenditures - Amort. of Principal	43,905,000	0	2,101,401	2,197,436	2,297,858	2,402,870	2,512,682	2,627,511	2,747,588
	Expense Expenditures - Amort. of Principal	84,808,500	0	84,808,500	0	0	0	0	0	0
FY 2012	**Conservation Resources Selected**									
14	**2014 Conservation - 2012$$**									
	Capital Expenditures - Amort. of Principal	45,724,200	0	0	2,188,473	2,288,486	2,393,070	2,502,433	2,616,795	2,736,382
	Expense Expenditures - Amort. of Principal	87,425,400	0	0	87,425,400	0	0	0	0	0
FY 2013	**Conservation Resources Selected**									
15	**2013 Conservation - 2013$$**									
	Capital Expenditures - Amort. of Principal	47,599,900	0	0	0	2,278,249	2,382,365	2,491,239	2,605,088	2,724,141
	Expense Expenditures - Amort. of Principal	90,257,000	0	0	0	90,257,000	0	0	0	0
FY 2014	**Conservation Resources Selected**									
16	**2012 Conservation - 2014$$**									
	Capital Expenditures - Amort. of Principal	49,552,800	0	0	0	0	2,371,719	2,480,107	2,593,447	2,711,968
	Expense Expenditures - Amort. of Principal	93,153,000	0	0	0	0	93,153,000	0	0	0
FY 2015	**Conservation Resources Selected**									
17	**2011 Conservation - 2015$$**									
	Capital Expenditures - Amort. of Principal	42,390,600	0	0	0	0	0	2,028,919	2,121,640	2,218,599
	Expense Expenditures - Amort. of Principal	93,522,800	0	0	0	0	0	93,522,800	0	0
TOTALS - CAPITAL EXPENDITURES -		394,638,700								
	AMORTIZATION OF PRINCIPAL	394,638,700	7,919,618	10,382,947	13,045,922	15,920,368	19,019,648	21,917,765	22,919,407	23,966,824
TOTALS - EXPENSE EXPENDITURES -		774,228,800								
	AMORTIZATION OF PRINCIPAL	774,228,800	325,062,100	84,808,500	87,425,400	90,257,000	93,153,000	93,522,800	0	0
TOTAL CONSERVATION PRINCIPAL										
	AND EXPENSE COSTS	1,168,867,500	332,981,718	95,191,447	100,471,322	106,177,368	112,172,648	115,440,565	22,919,407	23,966,824
PERCENTAGE OF TOTAL PRINCIPAL PAID		100.00%	28.49%	8.14%	8.60%	9.08%	9.60%	9.88%	1.96%	2.05%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID			28.49%	36.63%	45.23%	54.31%	63.91%	73.79%	75.75%	77.80%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD 73.79%
TOTAL INTEREST PAID ON EXPENSED PORTION $0

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011	**Conservation Resources Selected**												
13	**2015 Conservation - 2011$$**												
	Capital Expenditures - Amort. of Principal	2,873,153	3,004,456	3,141,760	3,285,338	3,435,478	3,592,480	3,756,656	3,928,333				
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0				
FY 2012	**Conservation Resources Selected**												
14	**2014 Conservation - 2012$$**												
	Capital Expenditures - Amort. of Principal	2,861,435	2,992,202	3,128,946	3,271,939	3,421,466	3,577,827	3,741,334	3,912,313	4,091,099			
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0			
FY 2013	**Conservation Resources Selected**												
15	**2013 Conservation - 2013$$**												
	Capital Expenditures - Amort. of Principal	2,848,634	2,978,817	3,114,949	3,257,302	3,406,160	3,561,822	3,724,597	3,894,811	4,072,804	4,258,922		
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0		
FY 2014	**Conservation Resources Selected**												
16	**2012 Conservation - 2014$$**												
	Capital Expenditures - Amort. of Principal	2,835,905	2,965,506	3,101,029	3,242,746	3,390,940	3,545,906	3,707,954	3,877,407	4,054,605	4,239,900	4,433,661	
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	
FY 2015	**Conservation Resources Selected**												
17	**2011 Conservation - 2015$$**												
	Capital Expenditures - Amort. of Principal	2,319,989	2,426,013	2,536,881	2,652,817	2,774,051	2,900,825	3,033,392	3,172,018	3,316,980	3,468,566	3,627,079	3,792,831
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	0
TOTALS - CAPITAL EXPENDITURES -													
	AMORTIZATION OF PRINCIPAL	25,062,107	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
TOTALS - EXPENSE EXPENDITURES -													
	AMORTIZATION OF PRINCIPAL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL CONSERVATION PRINCIPAL													
	AND EXPENSE COSTS	25,062,107	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
PERCENTAGE OF TOTAL PRINCIPAL PAID		2.14%	2.24%	2.34%	2.45%	2.56%	2.68%	2.80%	1.61%	1.33%	1.02%	0.69%	0.32%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAII		79.94%	82.18%	84.52%	86.97%	89.53%	92.21%	95.01%	96.62%	97.95%	98.97%	99.66%	99.98%

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	Inflation Adjustment	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	0.0457	4	0.0370
FY 2011	1.020232		5	0.0379
FY 2012	1.041582		6	0.0388
FY 2013	1.062788		7	0.0397
FY 2014	1.084313		15	0.0457
FY 2015	1.106094			

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected						
1	**2004 Conservation - 2010$$**	31.4	18,502.0	22,723.7	41,225.7	
	Capitalized Costs - Debt Service Requirements					$2,126,085.25
	Expensed Costs /Deferral Debt Service Requirements					$5,061,128.31
2	**2001 Conservation - 2010$$**	18.7	24,855.2	71.2	24,926.4	
	Capitalized Costs - Debt Service Requirements					$6,661.65
	Expensed Costs /Deferral Debt Service Requirements					$6,799,013.97
4	**2006 Conservation - 2010$$**	30.2	30,761.1	16,438.0	47,199.1	
	Capitalized Costs - Debt Service Requirements					1,537,979.70
	Expensed Costs /Deferral Debt Service Requirements					$8,414,542.97
5	**2007 Conservation - 2010$$**	28.5	41,499.7	11,453.5	52,953.2	
	Capitalized Costs - Debt Service Requirements					1,071,617.62
	Expensed Costs /Deferral Debt Service Requirements					$11,352,032.57
6	**2003 Conservation - 2010$$**	25.2	20,758.3	27,500.1	48,258.4	
	Capitalized Costs - Debt Service Requirements					2,572,976.98
	Expensed Costs /Deferral Debt Service Requirements					$5,678,327.74
7	**2005 Conservation - 2010$$**	20.0	25,443.0	16,719.5	42,162.5	
	Capitalized Costs - Debt Service Requirements					1,564,317.53
	Expensed Costs /Deferral Debt Service Requirements					$6,959,803.68
8	**2002 Conservation - 2010$$**	26.1	21,005.4	34,586.6	55,592.0	
	Capitalized Costs - Debt Service Requirements					3,236,007.34
	Expensed Costs /Deferral Debt Service Requirements					$5,745,920.69
9	**2008 Conservation - 2010$$**	34.8	65,070.9	8,214.0	73,284.9	
	Capitalized Costs - Debt Service Requirements					768,522.04
	Expensed Costs /Deferral Debt Service Requirements					$17,799,814.84
12	**2009 Conservation - 2010$$**	40.1	77,166.5	27,759.6	104,926.1	
	Capitalized Costs - Debt Service Requirements					2,597,256.44
	Expensed Costs /Deferral Debt Service Requirements					$21,108,504.91

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1
Expense		5,061.1	5,061.1	5,061.1	5,061.1	0.0	0.0	0.0	0.0	0.0	0.0
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Expense		6,799.0	6,799.0	6,799.0	6,799.0	0.0	0.0	0.0	0.0	0.0	0.0
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0
Expense		8,414.5	8,414.5	8,414.5	8,414.5	0.0	0.0	0.0	0.0	0.0	0.0
5	**2007 Conservation - 2010$$**										
Capital		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6
Expense		11,352.0	11,352.0	11,352.0	11,352.0	0.0	0.0	0.0	0.0	0.0	0.0
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0
Expense		5,678.3	5,678.3	5,678.3	5,678.3	0.0	0.0	0.0	0.0	0.0	0.0
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3
Expense		6,959.8	6,959.8	6,959.8	6,959.8	0.0	0.0	0.0	0.0	0.0	0.0
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0
Expense		5,745.9	5,745.9	5,745.9	5,745.9	0.0	0.0	0.0	0.0	0.0	0.0
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5
Expense		17,799.8	17,799.8	17,799.8	17,799.8	0.0	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3
Expense		21,108.5	21,108.5	21,108.5	21,108.5	0.0	0.0	0.0	0.0	0.0	0.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1					
Expense		0.0	0.0	0.0	0.0	0.0					
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7					
Expense		0.0	0.0	0.0	0.0	0.0					
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0					
Expense		0.0	0.0	0.0	0.0	0.0					
5	**2007 Conservation - 2010$$**										
		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6					
		0.0	0.0	0.0	0.0	0.0					
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0					
Expense		0.0	0.0	0.0	0.0	0.0					
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3					
Expense		0.0	0.0	0.0	0.0	0.0					
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0					
Expense		0.0	0.0	0.0	0.0	0.0					
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5					
Expense		0.0	0.0	0.0	0.0	0.0					
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3					
Expense		0.0	0.0	0.0	0.0	0.0					

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$	38.8	83,126.7	43,034.3	126,161.1	
13	**2015 Conservation - 2011$$**		84,808.5	43,905.0	128,713.5	
	Capitalized Costs - Debt Service Requirements					4,107,859.76
	Expensed Costs /Deferral Debt Service Requirements					$23,198,935.27
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$	38.8	83,935.2	43,898.8	127,833.9	
14	**2014 Conservation - 2012$$**		87,425.4	45,724.2	133,149.6	
	Capitalized Costs - Debt Service Requirements					4,278,068.59
	Expensed Costs /Deferral Debt Service Requirements					$23,914,775.00
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$	38.8	84,924.7	44,787.8	129,712.6	
15	**2013 Conservation - 2013$$**		90,257.0	47,599.9	137,856.9	
	Capitalized Costs - Debt Service Requirements					4,453,563.69
	Expensed Costs /Deferral Debt Service Requirements					$24,689,344.83
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$	38.8	85,909.7	45,699.7	131,609.5	
16	**2012 Conservation - 2014$$**		93,153.0	49,552.8	142,705.8	
	Capitalized Costs - Debt Service Requirements					4,636,281.82
	Expensed Costs /Deferral Debt Service Requirements					$25,481,530.95
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$	34.6	84,552.3	38,324.6	122,876.9	
17	**2011 Conservation - 2015$$**		93,522.8	42,390.6	135,913.4	
	Capitalized Costs - Debt Service Requirements					3,966,168.77
	Expensed Costs /Deferral Debt Service Requirements					$25,582,687.86

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		394,638.7	159,215.3	553,854.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	774,228.8		72,915.6	847,144.4
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	774,228.8	394,638.7	232,130.9	1,400,998.4

Principal Expense Costs	774,228.8
Interest Paid Expensed Costs	72,915.6
Principal Capital Costs	394,638.7
Interest Paid Capital Costs	159,215.3
Totals	1,400,998.4

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9
Expense		0.0	23,198.9	23,198.9	23,198.9	23,198.9	0.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1
Expense		0.0	0.0	23,914.8	23,914.8	23,914.8	23,914.8	0.0	0.0	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6
Expense		0.0	0.0	0.0	24,689.3	24,689.3	24,689.3	24,689.3	0.0	0.0	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3
Expense		0.0	0.0	0.0	0.0	25,481.5	25,481.5	25,481.5	25,481.5	0.0	0.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		0.0	0.0	0.0	0.0	0.0	25,582.7	25,582.7	25,582.7	25,582.7	0.0
TCC		15,481.5	19,589.4	23,867.5	28,321.1	32,957.4	36,923.6	36,923.6	36,923.6	36,923.6	36,923.6
TEC		88,918.9	112,117.8	136,032.6	160,721.9	97,284.5	99,668.3	75,753.5	51,064.2	25,582.7	0.0
TDSR		104,400.4	131,707.2	159,900.1	189,043.0	130,241.9	136,591.9	112,677.1	87,987.8	62,506.3	36,923.6

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9				
Expense		0.0	0.0	0.0	0.0	0.0	0.0				
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1			
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0			
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6		
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2
TEC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010 Conservation Resources Selected										
FY 2010 Conservation (9) Res. Selected - Total MW =		255								
1	**2004 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	22,723,700	1,087,612	1,137,316	1,189,291	1,243,642	1,300,476	1,359,908	1,422,056	1,487,044
	Expense Expenditures - Amort. of Principal	18,502,000	4,376,554	4,538,486	4,706,410	4,880,550	0	0	0	0
2	**2001 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	71,200	3,408	3,564	3,727	3,897	4,075	4,261	4,456	4,660
	Expense Expenditures - Amort. of Principal	24,855,200	5,879,372	6,096,908	6,322,494	6,556,426	0	0	0	0
4	**2006 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,438,000	786,763	822,718	860,317	899,633	940,746	983,738	1,028,695	1,075,707
	Expense Expenditures - Amort. of Principal	30,761,100	7,276,382	7,545,608	7,824,796	8,114,314	0	0	0	0
5	**2007 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	11,453,500	548,193	573,245	599,443	626,837	655,484	685,439	716,764	749,520
	Expense Expenditures - Amort. of Principal	41,499,700	9,816,544	10,179,756	10,556,407	10,946,993	0	0	0	0
6	**2003 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,500,100	1,316,222	1,376,374	1,439,274	1,505,049	1,573,830	1,645,754	1,720,965	1,799,613
	Expense Expenditures - Amort. of Principal	20,758,300	4,910,271	5,091,951	5,280,353	5,475,725	0	0	0	0
7	**2005 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,719,500	800,237	836,808	875,050	915,040	956,857	1,000,585	1,046,312	1,094,128
	Expense Expenditures - Amort. of Principal	25,443,000	6,018,413	6,241,094	6,472,015	6,711,478	0	0	0	0
8	**2002 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	34,586,600	1,655,399	1,731,051	1,810,160	1,892,884	1,979,389	2,069,847	2,164,439	2,263,354
	Expense Expenditures - Amort. of Principal	21,005,400	4,968,721	5,152,564	5,343,209	5,540,906	0	0	0	0
9	**2008 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	8,214,000	393,142	411,109	429,896	449,543	470,087	491,570	514,035	537,526
	Expense Expenditures - Amort. of Principal	65,070,900	15,392,192	15,961,703	16,552,286	17,164,719	0	0	0	0
12	**2009 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,759,600	1,328,642	1,389,361	1,452,855	1,519,250	1,588,680	1,661,283	1,737,204	1,816,594
	Expense Expenditures - Amort. of Principal	77,166,500	18,253,344	18,928,718	19,629,081	20,355,357	0	0	0	0

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are deferred and amortized / financed over 4 - years

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected													
FY 2010 Conservation (9) Res. Selected - Total MW =													
1	**2004 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,555,002	1,626,065	1,700,376	1,778,084	1,859,342	1,944,314	2,033,172					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
2	**2001 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	4,873	5,095	5,328	5,572	5,826	6,093	6,365					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
4	**2006 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,124,866	1,176,273	1,230,029	1,286,241	1,345,022	1,406,490	1,470,762					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
5	**2007 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	783,773	819,592	857,047	896,214	937,171	980,000	1,024,778					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
6	**2003 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,881,855	1,967,856	2,057,787	2,151,828	2,250,166	2,352,999	2,460,528					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
7	**2005 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,144,130	1,196,417	1,251,093	1,308,268	1,368,056	1,430,576	1,495,943					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
8	**2002 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	2,366,789	2,474,952	2,588,057	2,706,331	2,830,011	2,959,342	3,094,595					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
9	**2008 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	562,091	587,778	614,640	642,729	672,102	702,817	734,935					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
12	**2009 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,899,612	1,986,424	2,077,204	2,172,132	2,271,399	2,375,202	2,483,758					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					

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= Expensed costs are deferred and amortized / financed over 4 - years

ALTERNATIVE - 2

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2011	**Conservation Resources Selected**									
13	**2015 Conservation - 2011$$**	43,905,000	0	2,101,401	2,197,436	2,297,858	2,402,870	2,512,682	2,627,511	2,747,588
	Capital Expenditures - Amort. of Principal	84,808,500	0	20,061,020	20,803,278	21,573,000	22,371,202	0	0	0
	Expense Expenditures - Amort. of Principal									
FY 2012	**Conservation Resources Selected**									
14	**2014 Conservation - 2012$$**									
	Capital Expenditures - Amort. of Principal	45,724,200	0	0	2,188,473	2,288,486	2,393,070	2,502,433	2,616,795	2,736,382
	Expense Expenditures - Amort. of Principal	87,425,400	0	0	20,680,035	21,445,196	22,238,669	23,061,500	0	0
FY 2013	**Conservation Resources Selected**									
15	**2013 Conservation - 2013$$**									
	Capital Expenditures - Amort. of Principal	47,599,900	0	0	0	2,278,249	2,382,365	2,491,239	2,605,088	2,724,141
	Expense Expenditures - Amort. of Principal	90,257,000	0	0	0	21,349,836	22,139,780	22,958,952	23,808,432	0
FY 2014	**Conservation Resources Selected**									
16	**2012 Conservation - 2014$$**									
	Capital Expenditures - Amort. of Principal	49,552,800	0	0	0	0	2,371,719	2,480,107	2,593,447	2,711,968
	Expense Expenditures - Amort. of Principal	93,153,000	0	0	0	0	22,034,870	22,850,160	23,695,616	24,572,354
FY 2015	**Conservation Resources Selected**									
17	**2011 Conservation - 2015$$**									
	Capital Expenditures - Amort. of Principal	42,390,600	0	0	0	0	0	2,028,919	2,121,640	2,218,599
	Expense Expenditures - Amort. of Principal	93,522,800	0	0	0	0	0	22,122,344	22,940,871	23,789,683
TOTALS - CAPITAL EXPENDITURES -		394,638,700								
	AMORTIZATION OF PRINCIPAL	394,638,700	7,919,618	10,382,947	13,045,922	15,920,368	19,019,648	21,917,765	22,919,407	23,966,824
TOTALS - EXPENSE EXPENDITURES -		774,228,800								
	AMORTIZATION OF PRINCIPAL	774,228,800	76,891,793	99,797,808	124,170,364	150,114,500	88,784,521	90,992,956	70,444,919	48,362,037
TOTAL CONSERVATION PRINCIPAL COSTS		1,168,867,500	84,811,411	110,180,755	137,216,286	166,034,868	107,804,169	112,910,721	93,364,326	72,328,861
PERCENTAGE OF TOTAL PRINCIPAL PAID		100.00%	7.26%	9.43%	11.74%	14.20%	9.22%	9.66%	7.99%	6.19%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID			7.26%	16.69%	28.43%	42.63%	51.85%	61.51%	69.50%	75.69%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD	61.51%
TOTAL INTEREST PAID ON EXPENSED PORTION	$72,916,659
INTEREST EXPENSE - % OF EXPENSED CONSERVATION EXPENDITURES	9.42%

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ALTERNATIVE - 2

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011	Conservation Resources Selected												
13	2015 Conservation - 2011$$	2,873,153	3,004,456	3,141,760	3,285,338	3,435,478	3,592,480	3,756,656	3,928,333				
	Capital Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0				
	Expense Expenditures - Amort. of Principal												
FY 2012	Conservation Resources Selected												
14	2014 Conservation - 2012$$												
	Capital Expenditures - Amort. of Principal	2,861,435	2,992,202	3,128,946	3,271,939	3,421,466	3,577,827	3,741,334	3,912,313	4,091,099			
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0			
FY 2013	Conservation Resources Selected												
15	2013 Conservation - 2013$$												
	Capital Expenditures - Amort. of Principal	2,848,634	2,978,817	3,114,949	3,257,302	3,406,160	3,561,822	3,724,597	3,894,811	4,072,804	4,258,922		
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0		
FY 2014	Conservation Resources Selected												
16	2012 Conservation - 2014$$												
	Capital Expenditures - Amort. of Principal	2,835,905	2,965,506	3,101,029	3,242,746	3,390,940	3,545,906	3,707,954	3,877,407	4,054,605	4,239,900	4,433,661	
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0	0	
FY 2015	Conservation Resources Selected												
17	2011 Conservation - 2015$$												
	Capital Expenditures - Amort. of Principal	2,319,989	2,426,013	2,536,881	2,652,817	2,774,051	2,900,825	3,033,392	3,172,018	3,316,980	3,468,566	3,627,079	3,792,831
	Expense Expenditures - Amort. of Principal	24,669,902	0	0	0	0	0	0	0	0	0	0	0
TOTALS - CAPITAL EXPENDITURES -	AMORTIZATION OF PRINCIPAL	25,062,107	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
TOTALS - EXPENSE EXPENDITURES -	AMORTIZATION OF PRINCIPAL	24,669,902	0	0	0	0	0	0	0	0	0	0	0
TOTAL CONSERVATION PRINCIPAL COSTS		49,732,009	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
PERCENTAGE OF TOTAL PRINCIPAL PAID		4.25%	2.24%	2.34%	2.45%	2.56%	2.68%	2.80%	1.61%	1.33%	1.02%	0.69%	0.32%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		79.94%	82.18%	84.52%	86.97%	89.53%	92.21%	95.01%	96.62%	97.95%	98.97%	99.66%	99.98%

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	Inflation Adjustment	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	0.0457	4	0.0370
FY 2011	1.020232		5	0.0379
FY 2012	1.041582		6	0.0388
FY 2013	1.062788		7	0.0397
FY 2014	1.084313		15	0.0457
FY 2015	1.106094			

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2010 Conservation Resources Selected						
1	2004 Conservation - 2010$$	31.4	18,502.0	22,723.7	41,225.7	
	Capitalized Costs - Debt Service Requirements					$2,126,085.25
	Expensed Costs /Deferral Debt Service Requirements					$4,131,563.31
2	2001 Conservation - 2010$$	18.7	24,855.2	71.2	24,926.4	
	Capitalized Costs - Debt Service Requirements					$6,661.65
	Expensed Costs /Deferral Debt Service Requirements					$5,550,255.78
4	2006 Conservation - 2010$$	30.2	30,761.1	16,438.0	47,199.1	
	Capitalized Costs - Debt Service Requirements					1,537,979.70
	Expensed Costs /Deferral Debt Service Requirements					$6,869,064.54
5	2007 Conservation - 2010$$	28.5	41,499.7	11,453.5	52,953.2	
	Capitalized Costs - Debt Service Requirements					1,071,617.62
	Expensed Costs /Deferral Debt Service Requirements					$9,267,032.64
6	2003 Conservation - 2010$$	25.2	20,758.3	27,500.1	48,258.4	
	Capitalized Costs - Debt Service Requirements					2,572,976.98
	Expensed Costs /Deferral Debt Service Requirements					$4,635,403.24
7	2005 Conservation - 2010$$	20.0	25,443.0	16,719.5	42,162.5	
	Capitalized Costs - Debt Service Requirements					1,564,317.53
	Expensed Costs /Deferral Debt Service Requirements					$5,681,513.64
8	2002 Conservation - 2010$$	26.1	21,005.4	34,586.6	55,592.0	
	Capitalized Costs - Debt Service Requirements					3,236,007.34
	Expensed Costs /Deferral Debt Service Requirements					$4,690,581.56
9	2008 Conservation - 2010$$	34.8	65,070.9	8,214.0	73,284.9	
	Capitalized Costs - Debt Service Requirements					768,522.04
	Expensed Costs /Deferral Debt Service Requirements					$14,530,566.59
12	2009 Conservation - 2010$$	40.1	77,166.5	27,759.6	104,926.1	
	Capitalized Costs - Debt Service Requirements					2,597,256.44
	Expensed Costs /Deferral Debt Service Requirements					$17,231,557.68

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1
Expense		4,131.6	4,131.6	4,131.6	4,131.6	4,131.6	0.0	0.0	0.0	0.0	0.0
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Expense		5,550.3	5,550.3	5,550.3	5,550.3	5,550.3	0.0	0.0	0.0	0.0	0.0
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0
Expense		6,869.1	6,869.1	6,869.1	6,869.1	6,869.1	0.0	0.0	0.0	0.0	0.0
5	**2007 Conservation - 2010$$**										
Capital		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6
Expense		9,267.0	9,267.0	9,267.0	9,267.0	9,267.0	0.0	0.0	0.0	0.0	0.0
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0
Expense		4,635.4	4,635.4	4,635.4	4,635.4	4,635.4	0.0	0.0	0.0	0.0	0.0
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3
Expense		5,681.5	5,681.5	5,681.5	5,681.5	5,681.5	0.0	0.0	0.0	0.0	0.0
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0
Expense		4,690.6	4,690.6	4,690.6	4,690.6	4,690.6	0.0	0.0	0.0	0.0	0.0
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5
Expense		14,530.6	14,530.6	14,530.6	14,530.6	14,530.6	0.0	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3
Expense		17,231.6	17,231.6	17,231.6	17,231.6	17,231.6	0.0	0.0	0.0	0.0	0.0

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ALTERNATIVE - 3

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1					
Expense		0.0	0.0	0.0	0.0	0.0					
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7					
Expense		0.0	0.0	0.0	0.0	0.0					
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0					
Expense		0.0	0.0	0.0	0.0	0.0					
5	**2007 Conservation - 2010$$**										
		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6					
		0.0	0.0	0.0	0.0	0.0					
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0					
Expense		0.0	0.0	0.0	0.0	0.0					
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3					
Expense		0.0	0.0	0.0	0.0	0.0					
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0					
Expense		0.0	0.0	0.0	0.0	0.0					
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5					
Expense		0.0	0.0	0.0	0.0	0.0					
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3					
Expense		0.0	0.0	0.0	0.0	0.0					

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$	38.8	83,126.7	43,034.3	126,161.1	
13	**2015 Conservation - 2011$$**		84,808.5	43,905.0	128,713.5	
	Capitalized Costs - Debt Service Requirements					4,107,859.76
	Expensed Costs /Deferral Debt Service Requirements					$18,938,043.84
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$	38.8	83,935.2	43,898.8	127,833.9	
14	**2014 Conservation - 2012$$**		87,425.4	45,724.2	133,149.6	
	Capitalized Costs - Debt Service Requirements					4,278,068.59
	Expensed Costs /Deferral Debt Service Requirements					$19,522,407.04
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$	38.8	84,924.7	44,787.8	129,712.6	
15	**2013 Conservation - 2013$$**		90,257.0	47,599.9	137,856.9	
	Capitalized Costs - Debt Service Requirements					4,453,563.69
	Expensed Costs /Deferral Debt Service Requirements					$20,154,713.53
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$	38.8	85,909.7	45,699.7	131,609.5	
16	**2012 Conservation - 2014$$**		93,153.0	49,552.8	142,705.8	
	Capitalized Costs - Debt Service Requirements					4,636,281.82
	Expensed Costs /Deferral Debt Service Requirements					$20,801,400.78
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$	34.6	84,552.3	38,324.6	122,876.9	
17	**2011 Conservation - 2015$$**		93,522.8	42,390.6	135,913.4	
	Capitalized Costs - Debt Service Requirements					3,966,168.77
	Expensed Costs /Deferral Debt Service Requirements					$20,883,978.45

($ 000)

	Principal Expensed Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		394,638.7	159,215.3	553,854.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	774,228.8		90,212.2	864,441.0
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	774,228.8	394,638.7	249,427.5	1,418,295.0

Principal Expense Costs	774,228.8
Interest Paid Expensed Costs	90,212.2
Principal Capital Costs	394,638.7
Interest Paid Capital Costs	159,215.3
Totals	1,418,295.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2011 Conservation Resources Selected										
13 2015 Conservation - 2011$$										
Capital	0.0	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9
Expense	0.0	18,938.0	18,938.0	18,938.0	18,938.0	18,938.0	0.0	0.0	0.0	0.0
FY 2012 Conservation Resources Selected										
14 2014 Conservation - 2012$$										
Capital	0.0	0.0	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1
Expense	0.0	0.0	19,522.4	19,522.4	19,522.4	19,522.4	19,522.4	0.0	0.0	0.0
FY 2013 Conservation Resources Selected										
15 2013 Conservation - 2013$$										
Capital	0.0	0.0	0.0	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6
Expense	0.0	0.0	0.0	20,154.7	20,154.7	20,154.7	20,154.7	20,154.7	0.0	0.0
FY 2014 Conservation Resources Selected										
16 2012 Conservation - 2014$$										
Capital	0.0	0.0	0.0	0.0	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3
Expense	0.0	0.0	0.0	0.0	20,801.4	20,801.4	20,801.4	20,801.4	20,801.4	0.0
FY 2015 Conservation Resources Selected										
17 2011 Conservation - 2015$$										
Capital	0.0	0.0	0.0	0.0	0.0	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense	0.0	0.0	0.0	0.0	0.0	20,884.0	20,884.0	20,884.0	20,884.0	20,884.0
TCC	15,481.5	19,589.4	23,867.5	28,321.1	32,957.4	36,923.6	36,923.6	36,923.6	36,923.6	36,923.6
TEC	72,587.7	91,525.7	111,048.1	131,202.8	152,004.2	100,300.5	81,362.5	61,840.1	41,685.4	20,884.0
TDSR	88,069.2	111,115.1	134,915.6	159,523.9	184,961.6	137,224.1	118,286.1	98,763.7	78,609.0	57,807.6

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Expensed costs are deferred and financed over 5-years

ALTERNATIVE - 3

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9				
Expense		0.0	0.0	0.0	0.0	0.0	0.0				
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1			
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0			
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6		
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2
TEC		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2

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ALTERNATIVE - 3

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010 Conservation Resources Selected										
FY 2010 Conservation (9) Res. Selected - Total MW =		255								
1	**2004 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	22,723,700	1,087,612	1,137,316	1,189,291	1,243,642	1,300,476	1,359,908	1,422,056	1,487,044
	Expense Expenditures - Amort. of Principal	18,502,000	3,430,337	3,560,347	3,695,284	3,835,335	3,980,697	0	0	0
2	**2001 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	71,200	3,408	3,564	3,727	3,897	4,075	4,261	4,456	4,660
	Expense Expenditures - Amort. of Principal	24,855,200	4,608,244	4,782,896	4,964,168	5,152,310	5,347,582	0	0	0
4	**2006 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,438,000	786,763	822,718	860,317	899,633	940,746	983,738	1,028,695	1,075,707
	Expense Expenditures - Amort. of Principal	30,761,100	5,703,219	5,919,371	6,143,715	6,376,562	6,618,233	0	0	0
5	**2007 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	11,453,500	548,193	573,245	599,443	626,837	655,484	685,439	716,764	749,520
	Expense Expenditures - Amort. of Principal	41,499,700	7,694,194	7,985,804	8,288,466	8,602,599	8,928,637	0	0	0
6	**2003 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,500,100	1,316,222	1,376,374	1,439,274	1,505,049	1,573,830	1,645,754	1,720,965	1,799,613
	Expense Expenditures - Amort. of Principal	20,758,300	3,848,663	3,994,528	4,145,920	4,303,051	4,466,138	0	0	0
7	**2005 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,719,500	800,237	836,808	875,050	915,040	956,857	1,000,585	1,046,312	1,094,128
	Expense Expenditures - Amort. of Principal	25,443,000	4,717,224	4,896,007	5,081,566	5,274,157	5,474,046	0	0	0
8	**2002 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	34,586,600	1,655,399	1,731,051	1,810,160	1,892,884	1,979,389	2,069,847	2,164,439	2,263,354
	Expense Expenditures - Amort. of Principal	21,005,400	3,894,477	4,042,078	4,195,273	4,354,274	4,519,298	0	0	0
9	**2008 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	8,214,000	393,142	411,109	429,896	449,543	470,087	491,570	514,035	537,526
	Expense Expenditures - Amort. of Principal	65,070,900	12,064,380	12,521,620	12,996,189	13,488,745	13,999,966	0	0	0
12	**2009 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,759,600	1,328,642	1,389,361	1,452,855	1,519,250	1,588,680	1,661,283	1,737,204	1,816,594
	Expense Expenditures - Amort. of Principal	77,166,500	14,306,948	14,849,181	15,411,965	15,996,078	16,602,328	0	0	0

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ALTERNATIVE - 3

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected													
FY 2010 Conservation (9) Res. Selected - Total MW =													
1	**2004 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,555,002	1,626,065	1,700,376	1,778,084	1,859,342	1,944,314	2,033,172					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
2	**2001 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	4,873	5,095	5,328	5,572	5,826	6,093	6,365					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
4	**2006 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,124,866	1,176,273	1,230,029	1,286,241	1,345,022	1,406,490	1,470,762					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
5	**2007 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	783,773	819,592	857,047	896,214	937,171	980,000	1,024,778					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
6	**2003 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,881,855	1,967,856	2,057,787	2,151,828	2,250,166	2,352,999	2,460,528					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
7	**2005 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,144,130	1,196,417	1,251,093	1,308,268	1,368,056	1,430,576	1,495,943					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
8	**2002 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	2,366,789	2,474,952	2,588,057	2,706,331	2,830,011	2,959,342	3,094,595					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
9	**2008 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	562,091	587,778	614,640	642,729	672,102	702,817	734,935					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
12	**2009 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,899,612	1,986,424	2,077,204	2,172,132	2,271,399	2,375,202	2,483,758					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					

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ALTERNATIVE - 3

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2011	**Conservation Resources Selected**									
13	**2015 Conservation - 2011$$**	43,905,000	0	2,101,401	2,197,436	2,297,858	2,402,870	2,512,682	2,627,511	2,747,588
	Capital Expenditures - Amort. of Principal	84,808,500	0	15,723,802	16,319,734	16,938,252	17,580,212	18,246,500	0	0
	Expense Expenditures - Amort. of Principal									
FY 2012	**Conservation Resources Selected**									
14	**2014 Conservation - 2012$$**									
	Capital Expenditures - Amort. of Principal	45,724,200	0	0	2,188,473	2,288,486	2,393,070	2,502,433	2,616,795	2,736,382
	Expense Expenditures - Amort. of Principal	87,425,400	0	0	16,208,984	16,823,305	17,460,908	18,122,677	18,809,526	0
FY 2013	**Conservation Resources Selected**									
15	**2013 Conservation - 2013$$**									
	Capital Expenditures - Amort. of Principal	47,599,900	0	0	0	2,278,249	2,382,365	2,491,239	2,605,088	2,724,141
	Expense Expenditures - Amort. of Principal	90,257,000	0	0	0	16,733,974	17,368,191	18,026,446	18,709,648	19,418,741
FY 2014	**Conservation Resources Selected**									
16	**2012 Conservation - 2014$$**									
	Capital Expenditures - Amort. of Principal	49,552,800	0	0	0	0	2,371,719	2,480,107	2,593,447	2,711,968
	Expense Expenditures - Amort. of Principal	93,153,000	0	0	0	0	17,270,902	17,925,469	18,604,845	19,309,968
FY 2015	**Conservation Resources Selected**									
17	**2011 Conservation - 2015$$**									
	Capital Expenditures - Amort. of Principal	42,390,600	0	0	0	0	0	2,028,919	2,121,640	2,218,599
	Expense Expenditures - Amort. of Principal	93,522,800	0	0	0	0	0	17,339,464	17,996,630	18,678,702
TOTALS - CAPITAL EXPENDITURES -		394,638,700								
	AMORTIZATION OF PRINCIPAL	394,638,700	7,919,618	10,382,947	13,045,922	15,920,368	19,019,648	21,917,765	22,919,407	23,966,824
TOTALS - EXPENSE EXPENDITURES -		774,228,800								
	AMORTIZATION OF PRINCIPAL	774,228,800	60,267,686	78,275,634	97,451,264	117,878,642	139,617,138	89,660,556	74,120,649	57,407,411
TOTAL CONSERVATION PRINCIPAL COSTS		1,168,867,500	68,187,304	88,658,581	110,497,186	133,799,010	158,636,786	111,578,321	97,040,056	81,374,235
PERCENTAGE OF TOTAL PRINCIPAL PAID		100.00%	5.83%	7.58%	9.45%	11.45%	13.57%	9.55%	8.30%	6.96%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID			5.83%	13.41%	22.86%	34.31%	47.88%	$\boxed{57.43\%}$	65.73%	72.69%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD	57.43%
TOTAL INTEREST PAID ON EXPENSED PORTION	$90,212,200
INTEREST EXPENSE - % OF EXPENSED CONSERVATION EXPENDITURES	11.65%

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ALTERNATIVE - 3

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011	**Conservation Resources Selected**												
13	**2015 Conservation - 2011$$**	2,873,153	3,004,456	3,141,760	3,285,338	3,435,478	3,592,480	3,756,656	3,928,333				
	Capital Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0				
	Expense Expenditures - Amort. of Principal												
FY 2012	**Conservation Resources Selected**												
14	**2014 Conservation - 2012$$**												
	Capital Expenditures - Amort. of Principal	2,861,435	2,992,202	3,128,946	3,271,939	3,421,466	3,577,827	3,741,334	3,912,313	4,091,099			
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0			
FY 2013	**Conservation Resources Selected**												
15	**2013 Conservation - 2013$$**												
	Capital Expenditures - Amort. of Principal	2,848,634	2,978,817	3,114,949	3,257,302	3,406,160	3,561,822	3,724,597	3,894,811	4,072,804	4,258,922		
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0	0		
FY 2014	**Conservation Resources Selected**												
16	**2012 Conservation - 2014$$**												
	Capital Expenditures - Amort. of Principal	2,835,905	2,965,506	3,101,029	3,242,746	3,390,940	3,545,906	3,707,954	3,877,407	4,054,605	4,239,900	4,433,661	
	Expense Expenditures - Amort. of Principal	20,041,816	0	0	0	0	0	0	0	0	0	0	
FY 2015	**Conservation Resources Selected**												
17	**2011 Conservation - 2015$$**												
	Capital Expenditures - Amort. of Principal	2,319,989	2,426,013	2,536,881	2,652,817	2,774,051	2,900,825	3,033,392	3,172,018	3,316,980	3,468,566	3,627,079	3,792,831
	Expense Expenditures - Amort. of Principal	19,386,625	20,121,379	0	0	0	0	0	0	0	0	0	0
TOTALS - CAPITAL EXPENDITURES -	AMORTIZATION OF PRINCIPAL	25,062,107	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
TOTALS - EXPENSE EXPENDITURES -	AMORTIZATION OF PRINCIPAL	39,428,441	20,121,379	0	0	0	0	0	0	0	0	0	0
TOTAL CONSERVATION PRINCIPAL COSTS		64,490,548	46,328,825	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
PERCENTAGE OF TOTAL PRINCIPAL PAID		5.52%	3.96%	2.34%	2.45%	2.56%	2.68%	2.80%	1.61%	1.33%	1.02%	0.69%	0.32%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		78.21%	82.17%	84.51%	86.96%	89.52%	92.20%	95.00%	96.61%	97.94%	98.96%	99.65%	99.97%

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ALTERNATIVE - 4

	Inflation Adjustment	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	0.0457	4	0.0370
FY 2011	1.020232		5	0.0379
FY 2012	1.041582		6	0.0388
FY 2013	1.062788		7	0.0397
FY 2014	1.084313		15	0.0457
FY 2015	1.106094			

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt Service Whole Dollars
FY 2010 Conservation Resources Selected						
1	**2004 Conservation - 2010$$**	31.4	18,502.0	22,723.7	41,225.7	
	Capitalized Costs - Debt Service Requirements					$2,126,085.25
	Expensed Costs /Deferral Debt Service Requirements					$3,515,700.64
2	**2001 Conservation - 2010$$**	18.7	24,855.2	71.2	24,926.4	
	Capitalized Costs - Debt Service Requirements					$6,661.65
	Expensed Costs /Deferral Debt Service Requirements					$4,722,918.74
4	**2006 Conservation - 2010$$**	30.2	30,761.1	16,438.0	47,199.1	
	Capitalized Costs - Debt Service Requirements					1,537,979.70
	Expensed Costs /Deferral Debt Service Requirements					$5,845,142.09
5	**2007 Conservation - 2010$$**	28.5	41,499.7	11,453.5	52,953.2	
	Capitalized Costs - Debt Service Requirements					1,071,617.62
	Expensed Costs /Deferral Debt Service Requirements					$7,885,662.19
6	**2003 Conservation - 2010$$**	25.2	20,758.3	27,500.1	48,258.4	
	Capitalized Costs - Debt Service Requirements					2,572,976.98
	Expensed Costs /Deferral Debt Service Requirements					$3,944,436.74
7	**2005 Conservation - 2010$$**	20.0	25,443.0	16,719.5	42,162.5	
	Capitalized Costs - Debt Service Requirements					1,564,317.53
	Expensed Costs /Deferral Debt Service Requirements					$4,834,610.93
8	**2002 Conservation - 2010$$**	26.1	21,005.4	34,586.6	55,592.0	
	Capitalized Costs - Debt Service Requirements					3,236,007.34
	Expensed Costs /Deferral Debt Service Requirements					$3,991,390.03
9	**2008 Conservation - 2010$$**	34.8	65,070.9	8,214.0	73,284.9	
	Capitalized Costs - Debt Service Requirements					768,522.04
	Expensed Costs /Deferral Debt Service Requirements					$12,364,598.68
12	**2009 Conservation - 2010$$**	40.1	77,166.5	27,759.6	104,926.1	
	Capitalized Costs - Debt Service Requirements					2,597,256.44
	Expensed Costs /Deferral Debt Service Requirements					$14,662,972.30

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ALTERNATIVE - 4

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1
Expense		3,515.7	3,515.7	3,515.7	3,515.7	3,515.7	3,515.7	0.0	0.0	0.0	0.0
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Expense		4,722.9	4,722.9	4,722.9	4,722.9	4,722.9	4,722.9	0.0	0.0	0.0	0.0
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0
Expense		5,845.1	5,845.1	5,845.1	5,845.1	5,845.1	5,845.1	0.0	0.0	0.0	0.0
5	**2007 Conservation - 2010$$**										
Capital		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6
Expense		7,885.7	7,885.7	7,885.7	7,885.7	7,885.7	7,885.7	0.0	0.0	0.0	0.0
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0
Expense		3,944.4	3,944.4	3,944.4	3,944.4	3,944.4	3,944.4	0.0	0.0	0.0	0.0
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3
Expense		4,834.6	4,834.6	4,834.6	4,834.6	4,834.6	4,834.6	0.0	0.0	0.0	0.0
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0
Expense		3,991.4	3,991.4	3,991.4	3,991.4	3,991.4	3,991.4	0.0	0.0	0.0	0.0
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5
Expense		12,364.6	12,364.6	12,364.6	12,364.6	12,364.6	12,364.6	0.0	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3
Expense		14,663.0	14,663.0	14,663.0	14,663.0	14,663.0	14,663.0	0.0	0.0	0.0	0.0

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Expensed costs are deferred and financed over 6-years

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1					
Expense		0.0	0.0	0.0	0.0	0.0					
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7					
Expense		0.0	0.0	0.0	0.0	0.0					
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0					
Expense		0.0	0.0	0.0	0.0	0.0					
5	**2007 Conservation - 2010$$**										
		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6					
		0.0	0.0	0.0	0.0	0.0					
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0					
Expense		0.0	0.0	0.0	0.0	0.0					
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3					
Expense		0.0	0.0	0.0	0.0	0.0					
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0					
Expense		0.0	0.0	0.0	0.0	0.0					
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5					
Expense		0.0	0.0	0.0	0.0	0.0					
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3					
Expense		0.0	0.0	0.0	0.0	0.0					

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt Service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$	38.8	83,126.7	43,034.3	126,161.1	
13	**2015 Conservation - 2011$$**		84,808.5	43,905.0	128,713.5	
	Capitalized Costs - Debt Service Requirements					4,107,859.76
	Expensed Costs /Deferral Debt Service Requirements					$16,115,084.74
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$	38.8	83,935.2	43,898.8	127,833.9	
14	**2014 Conservation - 2012$$**		87,425.4	45,724.2	133,149.6	
	Capitalized Costs - Debt Service Requirements					4,278,068.59
	Expensed Costs /Deferral Debt Service Requirements					$16,612,341.09
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$	38.8	84,924.7	44,787.8	129,712.6	
15	**2013 Conservation - 2013$$**		90,257.0	47,599.9	137,856.9	
	Capitalized Costs - Debt Service Requirements					4,453,563.69
	Expensed Costs /Deferral Debt Service Requirements					$17,150,394.16
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$	38.8	85,909.7	45,699.7	131,609.5	
16	**2012 Conservation - 2014$$**		93,153.0	49,552.8	142,705.8	
	Capitalized Costs - Debt Service Requirements					4,636,281.82
	Expensed Costs /Deferral Debt Service Requirements					$17,700,684.35
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$	34.6	84,552.3	38,324.6	122,876.9	
17	**2011 Conservation - 2015$$**		93,522.8	42,390.6	135,913.4	
	Capitalized Costs - Debt Service Requirements					3,966,168.77
	Expensed Costs /Deferral Debt Service Requirements					$17,770,952.76

($ 000)

	Principal Expense Costs	Principal Capital Costs	Interest Paid	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		394,638.7	159,215.3	553,854.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	774,228.8		108,472.6	882,701.4
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	774,228.8	394,638.7	267,687.9	1,436,555.4

Principal Expense Costs	774,228.8
Interest Paid Expensed Costs	108,472.6
Principal Capital Costs	394,638.7
Interest Paid Capital Costs	159,215.3
Totals	1,436,555.4

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9
Expense		0.0	16,115.1	16,115.1	16,115.1	16,115.1	16,115.1	16,115.1	0.0	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1
Expense		0.0	0.0	16,612.3	16,612.3	16,612.3	16,612.3	16,612.3	16,612.3	0.0	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6
Expense		0.0	0.0	0.0	17,150.4	17,150.4	17,150.4	17,150.4	17,150.4	17,150.4	0.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3
Expense		0.0	0.0	0.0	0.0	17,700.7	17,700.7	17,700.7	17,700.7	17,700.7	17,700.7
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		0.0	0.0	0.0	0.0	0.0	17,771.0	17,771.0	17,771.0	17,771.0	17,771.0
TCC		15,481.5	19,589.4	23,867.5	28,321.1	32,957.4	36,923.6	36,923.6	36,923.6	36,923.6	36,923.6
TEC		61,767.4	77,882.5	94,494.8	111,645.2	129,345.9	147,116.9	85,349.5	69,234.4	52,622.1	35,471.7
TDSR		77,248.9	97,471.9	118,362.3	139,966.3	162,303.3	184,040.5	122,273.1	106,158.0	89,545.7	72,395.3

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9				
Expense		0.0	0.0	0.0	0.0	0.0	0.0				
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1			
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0			
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6		
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		17,771.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2
TEC		17,771.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		54,694.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2

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Scenario = Capitalized costs amortized / financed over 15 years,

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ALTERNATIVE - 4

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010	**Conservation Resources Selected**									
FY 2010	Conservation (9) Res. Selected - Total MW =	255								
1	**2004 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	22,723,700	1,087,612	1,137,316	1,189,291	1,243,642	1,300,476	1,359,908	1,422,056	1,487,044
	Expense Expenditures - Amort. of Principal	18,502,000	2,797,823	2,906,379	3,019,146	3,136,289	3,257,977	3,384,386	0	0
2	**2001 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	71,200	3,408	3,564	3,727	3,897	4,075	4,261	4,456	4,660
	Expense Expenditures - Amort. of Principal	24,855,200	3,758,537	3,904,368	4,055,858	4,213,225	4,376,698	4,546,514	0	0
4	**2006 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,438,000	786,763	822,718	860,317	899,633	940,746	983,738	1,028,695	1,075,707
	Expense Expenditures - Amort. of Principal	30,761,100	4,651,611	4,832,094	5,019,579	5,214,339	5,416,655	5,626,822	0	0
5	**2007 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	11,453,500	548,193	573,245	599,443	626,837	655,484	685,439	716,764	749,520
	Expense Expenditures - Amort. of Principal	41,499,700	6,275,474	6,518,962	6,771,898	7,034,647	7,307,592	7,591,127	0	0
6	**2003 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,500,100	1,316,222	1,376,374	1,439,274	1,505,049	1,573,830	1,645,754	1,720,965	1,799,613
	Expense Expenditures - Amort. of Principal	20,758,300	3,139,015	3,260,809	3,387,328	3,518,756	3,655,284	3,797,108	0	0
7	**2005 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,719,500	800,237	836,808	875,050	915,040	956,857	1,000,585	1,046,312	1,094,128
	Expense Expenditures - Amort. of Principal	25,443,000	3,847,423	3,996,703	4,151,775	4,312,864	4,480,203	4,654,032	0	0
8	**2002 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	34,586,600	1,655,399	1,731,051	1,810,160	1,892,884	1,979,389	2,069,847	2,164,439	2,263,354
	Expense Expenditures - Amort. of Principal	21,005,400	3,176,380	3,299,624	3,427,649	3,560,642	3,698,795	3,842,310	0	0
9	**2008 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	8,214,000	393,142	411,109	429,896	449,543	470,087	491,570	514,035	537,526
	Expense Expenditures - Amort. of Principal	65,070,900	9,839,848	10,221,634	10,618,234	11,030,221	11,458,194	11,902,769	0	0
12	**2009 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,759,600	1,328,642	1,389,361	1,452,855	1,519,250	1,588,680	1,661,283	1,737,204	1,816,594
	Expense Expenditures - Amort. of Principal	77,166,500	11,668,912	12,121,666	12,591,986	13,080,555	13,588,081	14,115,300	0	0

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ALTERNATIVE - 4

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010	**Conservation Resources Selected**												
FY 2010	Conservation (9) Res. Selected - Total MW =												
1	**2004 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,555,002	1,626,065	1,700,376	1,778,084	1,859,342	1,944,314	2,033,172					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
2	**2001 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	4,873	5,095	5,328	5,572	5,826	6,093	6,365					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
4	**2006 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,124,866	1,176,273	1,230,029	1,286,241	1,345,022	1,406,490	1,470,762					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
5	**2007 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	783,773	819,592	857,047	896,214	937,171	980,000	1,024,778					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
6	**2003 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,881,855	1,967,856	2,057,787	2,151,828	2,250,166	2,352,999	2,460,528					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
7	**2005 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,144,130	1,196,417	1,251,093	1,308,268	1,368,056	1,430,576	1,495,943					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
8	**2002 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	2,366,789	2,474,952	2,588,057	2,706,331	2,830,011	2,959,342	3,094,595					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
9	**2008 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	562,091	587,778	614,640	642,729	672,102	702,817	734,935					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
12	**2009 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,899,612	1,986,424	2,077,204	2,172,132	2,271,399	2,375,202	2,483,758					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					

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ALTERNATIVE - 4

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2011	**Conservation Resources Selected**									
13	**2015 Conservation - 2011$$**	43,905,000	0	2,101,401	2,197,436	2,297,858	2,402,870	2,512,682	2,627,511	2,747,588
	Capital Expenditures - Amort. of Principal	84,808,500	0	12,824,515	13,322,106	13,839,004	14,375,957	14,933,745	15,513,173	0
	Expense Expenditures - Amort. of Principal									
FY 2012	**Conservation Resources Selected**									
14	**2014 Conservation - 2012$$**									
	Capital Expenditures - Amort. of Principal	45,724,200	0	0	2,188,473	2,288,486	2,393,070	2,502,433	2,616,795	2,736,382
	Expense Expenditures - Amort. of Principal	87,425,400	0	0	13,220,235	13,733,181	14,266,028	14,819,550	15,394,548	15,991,858
FY 2013	**Conservation Resources Selected**									
15	**2013 Conservation - 2013$$**									
	Capital Expenditures - Amort. of Principal	47,599,900	0	0	0	2,278,249	2,382,365	2,491,239	2,605,088	2,724,141
	Expense Expenditures - Amort. of Principal	90,257,000	0	0	0	13,648,422	14,177,981	14,728,087	15,299,537	15,893,159
FY 2014	**Conservation Resources Selected**									
16	**2012 Conservation - 2014$$**									
	Capital Expenditures - Amort. of Principal	49,552,800	0	0	0	0	2,371,719	2,480,107	2,593,447	2,711,968
	Expense Expenditures - Amort. of Principal	93,153,000	0	0	0	0	14,086,348	14,632,898	15,200,654	15,790,440
FY 2015	**Conservation Resources Selected**									
17	**2011 Conservation - 2015$$**									
	Capital Expenditures - Amort. of Principal	42,390,600	0	0	0	0	0	2,028,919	2,121,640	2,218,599
	Expense Expenditures - Amort. of Principal	93,522,800	0	0	0	0	0	14,142,268	14,690,988	15,260,999
TOTALS - CAPITAL EXPENDITURES -		394,638,700								
	AMORTIZATION OF PRINCIPAL	394,638,700	7,919,618	10,382,947	13,045,922	15,920,368	19,019,648	21,917,765	22,919,407	23,966,824
TOTALS - EXPENSE EXPENDITURES -		774,228,800								
	AMORTIZATION OF PRINCIPAL	774,228,800	49,155,023	63,886,754	79,585,794	96,322,145	114,145,793	132,716,916	76,098,900	62,936,456
TOTAL CONSERVATION PRINCIPAL COSTS		1,168,867,500	57,074,641	74,269,701	92,631,716	112,242,513	133,165,441	154,634,681	99,018,307	86,903,280
PERCENTAGE OF TOTAL PRINCIPAL PAID		100.00%	4.88%	6.35%	7.92%	9.60%	11.39%	13.23%	8.47%	7.43%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID			4.88%	11.23%	19.15%	28.75%	40.14%	$\boxed{53.37\%}$	61.84%	69.27%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD	53.37%
TOTAL INTEREST PAID ON EXPENSED PORTION	$108,472,600
INTEREST EXPENSE - % OF EXPENSED CONSERVATION EXPENDITURES	14.01%

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ALTERNATIVE - 4

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011	**Conservation Resources Selected**												
13	**2015 Conservation - 2011$$**	2,873,153	3,004,456	3,141,760	3,285,338	3,435,478	3,592,480	3,756,656	3,928,333				
	Capital Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0				
	Expense Expenditures - Amort. of Principal												
FY 2012	**Conservation Resources Selected**												
14	**2014 Conservation - 2012$$**												
	Capital Expenditures - Amort. of Principal	2,861,435	2,992,202	3,128,946	3,271,939	3,421,466	3,577,827	3,741,334	3,912,313	4,091,099			
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0	0			
FY 2013	**Conservation Resources Selected**												
15	**2013 Conservation - 2013$$**												
	Capital Expenditures - Amort. of Principal	2,848,634	2,978,817	3,114,949	3,257,302	3,406,160	3,561,822	3,724,597	3,894,811	4,072,804	4,258,922		
	Expense Expenditures - Amort. of Principal	16,509,814	0	0	0	0	0	0	0	0	0		
FY 2014	**Conservation Resources Selected**												
16	**2012 Conservation - 2014$$**												
	Capital Expenditures - Amort. of Principal	2,835,905	2,965,506	3,101,029	3,242,746	3,390,940	3,545,906	3,707,954	3,877,407	4,054,605	4,239,900	4,433,661	
	Expense Expenditures - Amort. of Principal	16,403,109	17,039,551	0	0	0	0	0	0	0	0	0	
FY 2015	**Conservation Resources Selected**												
17	**2011 Conservation - 2015$$**												
	Capital Expenditures - Amort. of Principal	2,319,989	2,426,013	2,536,881	2,652,817	2,774,051	2,900,825	3,033,392	3,172,018	3,316,980	3,468,566	3,627,079	3,792,831
	Expense Expenditures - Amort. of Principal	15,853,125	16,468,227	17,107,193	0	0	0	0	0	0	0	0	0
TOTALS - CAPITAL EXPENDITURES -													
	AMORTIZATION OF PRINCIPAL	25,062,107	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
TOTALS - EXPENSE EXPENDITURES -													
	AMORTIZATION OF PRINCIPAL	48,766,048	33,507,778	17,107,193	0	0	0	0	0	0	0	0	0
TOTAL CONSERVATION PRINCIPAL COSTS		73,828,155	59,715,224	44,512,319	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
PERCENTAGE OF TOTAL PRINCIPAL PAID		6.32%	5.11%	3.81%	2.45%	2.56%	2.68%	2.80%	1.61%	1.33%	1.02%	0.69%	0.32%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		75.59%	80.70%	84.51%	86.96%	89.52%	92.20%	95.00%	96.61%	97.94%	98.96%	99.65%	99.97%

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	Inflation Adjustment	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	0.0457	4	0.0370
FY 2011	1.020232		5	0.0379
FY 2012	1.041582		6	0.0388
FY 2013	1.062788		7	0.0397
FY 2014	1.084313		15	0.0457
FY 2015	1.106094			

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt Service Whole Dollars
FY 2010 Conservation Resources Selected						
1	**2004 Conservation - 2010$$**	31.4	18,502.0	22,723.7	41,225.7	
	Capitalized Costs - Debt Service Requirements					$2,126,085.25
	Expensed Costs /Deferral Debt Service Requirements					$3,079,194.40
2	**2001 Conservation - 2010$$**	18.7	24,855.2	71.2	24,926.4	
	Capitalized Costs - Debt Service Requirements					$6,661.65
	Expensed Costs /Deferral Debt Service Requirements					$4,136,525.38
4	**2006 Conservation - 2010$$**	30.2	30,761.1	16,438.0	47,199.1	
	Capitalized Costs - Debt Service Requirements					1,537,979.70
	Expensed Costs /Deferral Debt Service Requirements					$5,119,414.48
5	**2007 Conservation - 2010$$**	28.5	41,499.7	11,453.5	52,953.2	
	Capitalized Costs - Debt Service Requirements					1,071,617.62
	Expensed Costs /Deferral Debt Service Requirements					$6,906,585.44
6	**2003 Conservation - 2010$$**	25.2	20,758.3	27,500.1	48,258.4	
	Capitalized Costs - Debt Service Requirements					2,572,976.98
	Expensed Costs /Deferral Debt Service Requirements					$3,454,699.01
7	**2005 Conservation - 2010$$**	20.0	25,443.0	16,719.5	42,162.5	
	Capitalized Costs - Debt Service Requirements					1,564,317.53
	Expensed Costs /Deferral Debt Service Requirements					$4,234,349.97
8	**2002 Conservation - 2010$$**	26.1	21,005.4	34,586.6	55,592.0	
	Capitalized Costs - Debt Service Requirements					3,236,007.34
	Expensed Costs /Deferral Debt Service Requirements					$3,495,822.61
9	**2008 Conservation - 2010$$**	34.8	65,070.9	8,214.0	73,284.9	
	Capitalized Costs - Debt Service Requirements					768,522.04
	Expensed Costs /Deferral Debt Service Requirements					$10,829,421.18
12	**2009 Conservation - 2010$$**	40.1	77,166.5	27,759.6	104,926.1	
	Capitalized Costs - Debt Service Requirements					2,597,256.44
	Expensed Costs /Deferral Debt Service Requirements					$12,842,430.79

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1
Expense		3,079.2	3,079.2	3,079.2	3,079.2	3,079.2	3,079.2	3,079.2	0.0	0.0	0.0
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Expense		4,136.5	4,136.5	4,136.5	4,136.5	4,136.5	4,136.5	4,136.5	0.0	0.0	0.0
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0
Expense		5,119.4	5,119.4	5,119.4	5,119.4	5,119.4	5,119.4	5,119.4	0.0	0.0	0.0
5	**2007 Conservation - 2010$$**										
Capital		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6
Expense		6,906.6	6,906.6	6,906.6	6,906.6	6,906.6	6,906.6	6,906.6	0.0	0.0	0.0
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0
Expense		3,454.7	3,454.7	3,454.7	3,454.7	3,454.7	3,454.7	3,454.7	0.0	0.0	0.0
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3
Expense		4,234.3	4,234.3	4,234.3	4,234.3	4,234.3	4,234.3	4,234.3	0.0	0.0	0.0
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0
Expense		3,495.8	3,495.8	3,495.8	3,495.8	3,495.8	3,495.8	3,495.8	0.0	0.0	0.0
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5
Expense		10,829.4	10,829.4	10,829.4	10,829.4	10,829.4	10,829.4	10,829.4	0.0	0.0	0.0
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3
Expense		12,842.4	12,842.4	12,842.4	12,842.4	12,842.4	12,842.4	12,842.4	0.0	0.0	0.0

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1					
Expense		0.0	0.0	0.0	0.0	0.0					
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7					
Expense		0.0	0.0	0.0	0.0	0.0					
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0					
Expense		0.0	0.0	0.0	0.0	0.0					
5	**2007 Conservation - 2010$$**										
		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6					
		0.0	0.0	0.0	0.0	0.0					
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0					
Expense		0.0	0.0	0.0	0.0	0.0					
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3					
Expense		0.0	0.0	0.0	0.0	0.0					
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0					
Expense		0.0	0.0	0.0	0.0	0.0					
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5					
Expense		0.0	0.0	0.0	0.0	0.0					
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3					
Expense		0.0	0.0	0.0	0.0	0.0					

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt Service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$	38.8	83,126.7	43,034.3	126,161.1	
13	**2015 Conservation - 2011$$**		84,808.5	43,905.0	128,713.5	
	Capitalized Costs - Debt Service Requirements					4,107,859.76
	Expensed Costs /Deferral Debt Service Requirements					$14,114,250.25
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$	38.8	83,935.2	43,898.8	127,833.9	
14	**2014 Conservation - 2012$$**		87,425.4	45,724.2	133,149.6	
	Capitalized Costs - Debt Service Requirements					4,278,068.59
	Expensed Costs /Deferral Debt Service Requirements					$14,549,767.70
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$	38.8	84,924.7	44,787.8	129,712.6	
15	**2013 Conservation - 2013$$**		90,257.0	47,599.9	137,856.9	
	Capitalized Costs - Debt Service Requirements					4,453,563.69
	Expensed Costs /Deferral Debt Service Requirements					$15,021,016.58
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$	38.8	85,909.7	45,699.7	131,609.5	
16	**2012 Conservation - 2014$$**		93,153.0	49,552.8	142,705.8	
	Capitalized Costs - Debt Service Requirements					4,636,281.82
	Expensed Costs /Deferral Debt Service Requirements					$15,502,983.23
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$	34.6	84,552.3	38,324.6	122,876.9	
17	**2011 Conservation - 2015$$**		93,522.8	42,390.6	135,913.4	
	Capitalized Costs - Debt Service Requirements					3,966,168.77
	Expensed Costs /Deferral Debt Service Requirements					$15,564,527.18

	Principal Expense Costs	Principal Capital Costs	Interest Paid Expense Costs	Cumulative Totals
TOTAL Capital Costs - Debt Ser. Req. = TCC		394,638.7	159,215.3	553,854.0
TOTAL Expense Costs - Debt Serv. Req. = TEC	774,228.8		127,727.5	901,956.3
TOTAL DEBT SERVICE REQUIREMENTS = TDSR	774,228.8	394,638.7	286,942.8	1,455,810.3

Principal Expense Costs	774,228.8
Interest Paid Expensed Costs	127,727.5
Principal Capital Costs	394,638.7
Interest Paid Capital Costs	159,215.3
Totals	1,455,810.3

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9
Expense		0.0	14,114.3	14,114.3	14,114.3	14,114.3	14,114.3	14,114.3	14,114.3	0.0	0.0
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1
Expense		0.0	0.0	14,549.8	14,549.8	14,549.8	14,549.8	14,549.8	14,549.8	14,549.8	0.0
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6
Expense		0.0	0.0	0.0	15,021.0	15,021.0	15,021.0	15,021.0	15,021.0	15,021.0	15,021.0
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3
Expense		0.0	0.0	0.0	0.0	15,503.0	15,503.0	15,503.0	15,503.0	15,503.0	15,503.0
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		0.0	0.0	0.0	0.0	0.0	15,564.5	15,564.5	15,564.5	15,564.5	15,564.5
TCC		15,481.5	19,589.4	23,867.5	28,321.1	32,957.4	36,923.6	36,923.6	36,923.6	36,923.6	36,923.6
TEC		54,098.3	68,212.6	82,762.4	97,783.4	113,286.4	128,850.9	128,850.9	74,752.6	60,638.3	46,088.5
TDSR		69,579.8	87,802.0	106,629.9	126,104.5	146,243.8	165,774.5	165,774.5	111,676.2	97,561.9	83,012.1

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Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9				
Expense		0.0	0.0	0.0	0.0	0.0	0.0				
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1			
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0			
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6		
Expense		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	
Expense		15,503.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		15,564.5	15,564.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TCC		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2
TEC		31,067.5	15,564.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TDSR		67,991.1	52,488.1	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010	**Conservation Resources Selected**									
FY 2010	Conservation (9) Res. Selected - Total MW =	255								
1	**2004 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	22,723,700	1,087,612	1,137,316	1,189,291	1,243,642	1,300,476	1,359,908	1,422,056	1,487,044
	Expense Expenditures - Amort. of Principal	18,502,000	2,344,665	2,437,748	2,534,526	2,635,147	2,739,762	2,848,531	2,961,621	0
2	**2001 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	71,200	3,408	3,564	3,727	3,897	4,075	4,261	4,456	4,660
	Expense Expenditures - Amort. of Principal	24,855,200	3,149,774	3,274,820	3,404,830	3,540,002	3,680,540	3,826,657	3,978,577	0
4	**2006 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,438,000	786,763	822,718	860,317	899,633	940,746	983,738	1,028,695	1,075,707
	Expense Expenditures - Amort. of Principal	30,761,100	3,898,198	4,052,957	4,213,859	4,381,149	4,555,081	4,735,918	4,923,938	0
5	**2007 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	11,453,500	548,193	573,245	599,443	626,837	655,484	685,439	716,764	749,520
	Expense Expenditures - Amort. of Principal	41,499,700	5,259,047	5,467,831	5,684,904	5,910,595	6,145,245	6,389,212	6,642,866	0
6	**2003 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,500,100	1,316,222	1,376,374	1,439,274	1,505,049	1,573,830	1,645,754	1,720,965	1,799,613
	Expense Expenditures - Amort. of Principal	20,758,300	2,630,594	2,735,029	2,843,610	2,956,501	3,073,874	3,195,907	3,322,785	0
7	**2005 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,719,500	800,237	836,808	875,050	915,040	956,857	1,000,585	1,046,312	1,094,128
	Expense Expenditures - Amort. of Principal	25,443,000	3,224,263	3,352,266	3,485,351	3,623,720	3,767,581	3,917,154	4,072,665	0
8	**2002 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	34,586,600	1,655,399	1,731,051	1,810,160	1,892,884	1,979,389	2,069,847	2,164,439	2,263,354
	Expense Expenditures - Amort. of Principal	21,005,400	2,661,909	2,767,586	2,877,460	2,991,695	3,110,465	3,233,950	3,362,335	0
9	**2008 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	8,214,000	393,142	411,109	429,896	449,543	470,087	491,570	514,035	537,526
	Expense Expenditures - Amort. of Principal	65,070,900	8,246,106	8,573,477	8,913,844	9,267,723	9,635,652	10,018,187	10,415,911	0
12	**2009 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,759,600	1,328,642	1,389,361	1,452,855	1,519,250	1,588,680	1,661,283	1,737,204	1,816,594
	Expense Expenditures - Amort. of Principal	77,166,500	9,778,921	10,167,144	10,570,780	10,990,440	11,426,760	11,880,403	12,352,052	0

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010	**Conservation Resources Selected**												
FY 2010	Conservation (9) Res. Selected - Total MW =												
1	**2004 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,555,002	1,626,065	1,700,376	1,778,084	1,859,342	1,944,314	2,033,172					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
2	**2001 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	4,873	5,095	5,328	5,572	5,826	6,093	6,365					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
4	**2006 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,124,866	1,176,273	1,230,029	1,286,241	1,345,022	1,406,490	1,470,762					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
5	**2007 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	783,773	819,592	857,047	896,214	937,171	980,000	1,024,778					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
6	**2003 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,881,855	1,967,856	2,057,787	2,151,828	2,250,166	2,352,999	2,460,528					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
7	**2005 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,144,130	1,196,417	1,251,093	1,308,268	1,368,056	1,430,576	1,495,943					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
8	**2002 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	2,366,789	2,474,952	2,588,057	2,706,331	2,830,011	2,959,342	3,094,595					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
9	**2008 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	562,091	587,778	614,640	642,729	672,102	702,817	734,935					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					
12	**2009 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,899,612	1,986,424	2,077,204	2,172,132	2,271,399	2,375,202	2,483,758					
	Expense Expenditures - Amort. of Principal	0	0	0	0	0	0	0					

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Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2011	**Conservation Resources Selected**									
13	**2015 Conservation - 2011$$**	43,905,000	0	2,101,401	2,197,436	2,297,858	2,402,870	2,512,682	2,627,511	2,747,588
	Capital Expenditures - Amort. of Principal	84,808,500	0	10,747,353	11,174,022	11,617,631	12,078,851	12,558,381	13,056,949	13,575,313
	Expense Expenditures - Amort. of Principal									
FY 2012	**Conservation Resources Selected**									
14	**2014 Conservation - 2012$$**									
	Capital Expenditures - Amort. of Principal	45,724,200	0	0	2,188,473	2,288,486	2,393,070	2,502,433	2,616,795	2,736,382
	Expense Expenditures - Amort. of Principal	87,425,400	0	0	11,078,980	11,518,815	11,976,112	12,451,564	12,945,891	13,459,843
FY 2013	**Conservation Resources Selected**									
15	**2013 Conservation - 2013$$**									
	Capital Expenditures - Amort. of Principal	47,599,900	0	0	0	2,278,249	2,382,365	2,491,239	2,605,088	2,724,141
	Expense Expenditures - Amort. of Principal	90,257,000	0	0	0	11,437,814	11,891,895	12,364,004	12,854,855	13,365,192
FY 2014	**Conservation Resources Selected**									
16	**2012 Conservation - 2014$$**									
	Capital Expenditures - Amort. of Principal	49,552,800	0	0	0	0	2,371,719	2,480,107	2,593,447	2,711,968
	Expense Expenditures - Amort. of Principal	93,153,000	0	0	0	0	11,804,809	12,273,460	12,760,716	13,267,317
FY 2015	**Conservation Resources Selected**									
17	**2011 Conservation - 2015$$**									
	Capital Expenditures - Amort. of Principal	42,390,600	0	0	0	0	0	2,028,919	2,121,640	2,218,599
	Expense Expenditures - Amort. of Principal	93,522,800	0	0	0	0	0	11,851,672	12,322,183	12,811,374
TOTALS - CAPITAL EXPENDITURES -		394,638,700								
	AMORTIZATION OF PRINCIPAL	394,638,700	7,919,618	10,382,947	13,045,922	15,920,368	19,019,648	21,917,765	22,919,407	23,966,824
TOTALS - EXPENSE EXPENDITURES -		774,228,800								
	AMORTIZATION OF PRINCIPAL	774,228,800	41,193,477	53,576,211	66,782,166	80,871,232	95,886,627	111,545,000	115,973,344	66,479,039
TOTAL CONSERVATION PRINCIPAL COSTS		1,168,867,500	49,113,095	63,959,158	79,828,088	96,791,600	114,906,275	133,462,765	138,892,751	90,445,863
PERCENTAGE OF TOTAL PRINCIPAL PAID		100.00%	4.20%	5.47%	6.83%	8.28%	9.83%	11.42%	11.88%	7.74%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID			4.20%	9.67%	16.50%	24.78%	34.61%	46.03%	57.91%	65.65%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD	46.03%
TOTAL INTEREST PAID ON EXPENSED PORTION	$127,727,500
INTEREST EXPENSE - % OF EXPENSED CONSERVATION EXPENDITURES	16.50%

Scenario = Capitalized costs amortized / financed over 15 years,
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Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011	**Conservation Resources Selected**												
13	**2015 Conservation - 2011$$**	2,873,153	3,004,456	3,141,760	3,285,338	3,435,478	3,592,480	3,756,656	3,928,333				
	Capital Expenditures - Amort. of Principal	0	0	0	0	0	0	0	0				
	Expense Expenditures - Amort. of Principal												
FY 2012	**Conservation Resources Selected**												
14	**2014 Conservation - 2012$$**												
	Capital Expenditures - Amort. of Principal	2,861,435	2,992,202	3,128,946	3,271,939	3,421,466	3,577,827	3,741,334	3,912,313	4,091,099			
	Expense Expenditures - Amort. of Principal	13,994,195	0	0	0	0	0	0	0	0			
FY 2013	**Conservation Resources Selected**												
15	**2013 Conservation - 2013$$**												
	Capital Expenditures - Amort. of Principal	2,848,634	2,978,817	3,114,949	3,257,302	3,406,160	3,561,822	3,724,597	3,894,811	4,072,804	4,258,922		
	Expense Expenditures - Amort. of Principal	13,895,790	14,447,450	0	0	0	0	0	0	0	0		
FY 2014	**Conservation Resources Selected**												
16	**2012 Conservation - 2014$$**												
	Capital Expenditures - Amort. of Principal	2,835,905	2,965,506	3,101,029	3,242,746	3,390,940	3,545,906	3,707,954	3,877,407	4,054,605	4,239,900	4,433,661	
	Expense Expenditures - Amort. of Principal	13,794,029	14,341,652	14,911,017	0	0	0	0	0	0	0	0	
FY 2015	**Conservation Resources Selected**												
17	**2011 Conservation - 2015$$**												
	Capital Expenditures - Amort. of Principal	2,319,989	2,426,013	2,536,881	2,652,817	2,774,051	2,900,825	3,033,392	3,172,018	3,316,980	3,468,566	3,627,079	3,792,831
	Expense Expenditures - Amort. of Principal	13,319,985	13,848,789	14,398,586	14,970,211	0	0	0	0	0	0	0	0
TOTALS - CAPITAL EXPENDITURES -	AMORTIZATION OF PRINCIPAL	25,062,107	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
TOTALS - EXPENSE EXPENDITURES -	AMORTIZATION OF PRINCIPAL	55,003,999	42,637,891	29,309,603	14,970,211	0	0	0	0	0	0	0	0
TOTAL CONSERVATION PRINCIPAL COSTS		80,066,106	68,845,337	56,714,729	43,627,752	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
PERCENTAGE OF TOTAL PRINCIPAL PAID		6.85%	5.89%	4.85%	3.73%	2.56%	2.68%	2.80%	1.61%	1.33%	1.02%	0.69%	0.32%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		72.50%	78.39%	83.24%	86.97%	89.53%	92.21%	95.01%	96.62%	97.95%	98.97%	99.66%	99.98%

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	Inflation Adjustment	Capitalized Conservation Interest Rate 15 - Year Maturity	Expensed Conservation Deferral/ Maturity # of Years	Expensed Conservation Interest Rate
FY 2010	1.000000	0.0457	4	0.0370
FY 2011	1.020232		5	0.0379
FY 2012	1.041582		6	0.0388
FY 2013	1.062788		7	0.0397
FY 2014	1.084313		15	0.0457
FY 2015	1.106094			

Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt Service Whole Dollars
FY 2010 Conservation Resources Selected						
1	2004 Conservation - 2010$$	31.4	18,502.0	22,723.7	41,225.7	
	Capitalized Costs - Debt Service Requirements					$2,126,085.25
	Expensed Costs /Deferral Debt Service Requirements					$1,731,092.62
2	2001 Conservation - 2010$$	18.7	24,855.2	71.2	24,926.4	
	Capitalized Costs - Debt Service Requirements					$6,661.65
	Expensed Costs /Deferral Debt Service Requirements					$2,325,513.63
4	2006 Conservation - 2010$$	30.2	30,761.1	16,438.0	47,199.1	
	Capitalized Costs - Debt Service Requirements					1,537,979.70
	Expensed Costs /Deferral Debt Service Requirements					$2,878,084.16
5	2007 Conservation - 2010$$	28.5	41,499.7	11,453.5	52,953.2	
	Capitalized Costs - Debt Service Requirements					1,071,617.62
	Expensed Costs /Deferral Debt Service Requirements					$3,882,813.98
6	2003 Conservation - 2010$$	25.2	20,758.3	27,500.1	48,258.4	
	Capitalized Costs - Debt Service Requirements					2,572,976.98
	Expensed Costs /Deferral Debt Service Requirements					$1,942,197.59
7	2005 Conservation - 2010$$	20.0	25,443.0	16,719.5	42,162.5	
	Capitalized Costs - Debt Service Requirements					1,564,317.53
	Expensed Costs /Deferral Debt Service Requirements					$2,380,509.64
8	2002 Conservation - 2010$$	26.1	21,005.4	34,586.6	55,592.0	
	Capitalized Costs - Debt Service Requirements					3,236,007.34
	Expensed Costs /Deferral Debt Service Requirements					$1,965,316.88
9	2008 Conservation - 2010$$	34.8	65,070.9	8,214.0	73,284.9	
	Capitalized Costs - Debt Service Requirements					768,522.04
	Expensed Costs /Deferral Debt Service Requirements					$6,088,193.41
12	2009 Conservation - 2010$$	40.1	77,166.5	27,759.6	104,926.1	
	Capitalized Costs - Debt Service Requirements					2,597,256.44
	Expensed Costs /Deferral Debt Service Requirements					$7,219,887.49

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1	2,126.1
Expense		1,731.1	1,731.1	1,731.1	1,731.1	1,731.1	1,731.1	1,731.1	1,731.1	1,731.1	1,731.1
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Expense		2,325.5	2,325.5	2,325.5	2,325.5	2,325.5	2,325.5	2,325.5	2,325.5	2,325.5	2,325.5
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0	1,538.0
Expense		2,878.1	2,878.1	2,878.1	2,878.1	2,878.1	2,878.1	2,878.1	2,878.1	2,878.1	2,878.1
5	**2007 Conservation - 2010$$**										
Capital		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6	1,071.6
Expense		3,882.8	3,882.8	3,882.8	3,882.8	3,882.8	3,882.8	3,882.8	3,882.8	3,882.8	3,882.8
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0	2,573.0
Expense		1,942.2	1,942.2	1,942.2	1,942.2	1,942.2	1,942.2	1,942.2	1,942.2	1,942.2	1,942.2
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3	1,564.3
Expense		2,380.5	2,380.5	2,380.5	2,380.5	2,380.5	2,380.5	2,380.5	2,380.5	2,380.5	2,380.5
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0	3,236.0
Expense		1,965.3	1,965.3	1,965.3	1,965.3	1,965.3	1,965.3	1,965.3	1,965.3	1,965.3	1,965.3
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5	768.5
Expense		6,088.2	6,088.2	6,088.2	6,088.2	6,088.2	6,088.2	6,088.2	6,088.2	6,088.2	6,088.2
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3	2,597.3
Expense		7,219.9	7,219.9	7,219.9	7,219.9	7,219.9	7,219.9	7,219.9	7,219.9	7,219.9	7,219.9

**Scenario = Capitalized costs are amortized and financed over 15 years,
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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation Resources Selected											
1	**2004 Conservation - 2010$$**										
Capital		2,126.1	2,126.1	2,126.1	2,126.1	2,126.1					
Expense		1,731.1	1,731.1	1,731.1	1,731.1	1,731.1					
2	**2001 Conservation - 2010$$**										
Capital		6.7	6.7	6.7	6.7	6.7					
Expense		2,325.5	2,325.5	2,325.5	2,325.5	2,325.5					
4	**2006 Conservation - 2010$$**										
Capital		1,538.0	1,538.0	1,538.0	1,538.0	1,538.0					
Expense		2,878.1	2,878.1	2,878.1	2,878.1	2,878.1					
5	**2007 Conservation - 2010$$**										
		1,071.6	1,071.6	1,071.6	1,071.6	1,071.6					
		3,882.8	3,882.8	3,882.8	3,882.8	3,882.8					
6	**2003 Conservation - 2010$$**										
Capital		2,573.0	2,573.0	2,573.0	2,573.0	2,573.0					
Expense		1,942.2	1,942.2	1,942.2	1,942.2	1,942.2					
7	**2005 Conservation - 2010$$**										
Capital		1,564.3	1,564.3	1,564.3	1,564.3	1,564.3					
Expense		2,380.5	2,380.5	2,380.5	2,380.5	2,380.5					
8	**2002 Conservation - 2010$$**										
Capital		3,236.0	3,236.0	3,236.0	3,236.0	3,236.0					
Expense		1,965.3	1,965.3	1,965.3	1,965.3	1,965.3					
9	**2008 Conservation - 2010$$**										
Capital		768.5	768.5	768.5	768.5	768.5					
Expense		6,088.2	6,088.2	6,088.2	6,088.2	6,088.2					
12	**2009 Conservation - 2010$$**										
Capital		2,597.3	2,597.3	2,597.3	2,597.3	2,597.3					
Expense		7,219.9	7,219.9	7,219.9	7,219.9	7,219.9					

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Res. Stack Order	Vintage Year	Conservation Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Annual Debt Service Whole Dollars
FY 2011 Conservation Resources Selected						
	2015 Conservation - 2010$$	38.8	83,126.7	43,034.3	126,161.1	
13	**2015 Conservation - 2011$$**		84,808.5	43,905.0	128,713.5	
	Capitalized Costs - Debt Service Requirements					4,107,859.76
	Expensed Costs /Deferral Debt Service Requirements					$7,934,891.80
FY 2012 Conservation Resources Selected						
	2014 Conservation - 2010$$	38.8	83,935.2	43,898.8	127,833.9	
14	**2014 Conservation - 2012$$**		87,425.4	45,724.2	133,149.6	
	Capitalized Costs - Debt Service Requirements					4,278,068.59
	Expensed Costs /Deferral Debt Service Requirements					$8,179,735.40
FY 2013 Conservation Resources Selected						
	2013 Conservation - 2010$$	38.8	84,924.7	44,787.8	129,712.6	
15	**2013 Conservation - 2013$$**		90,257.0	47,599.9	137,856.9	
	Capitalized Costs - Debt Service Requirements					4,453,563.69
	Expensed Costs /Deferral Debt Service Requirements					$8,444,666.9
FY 2014 Conservation Resources Selected						
	2012 Conservation - 2010$$	38.8	85,909.7	45,699.7	131,609.5	
16	**2012 Conservation - 2014$$**		93,153.0	49,552.8	142,705.8	
	Capitalized Costs - Debt Service Requirements					4,636,281.82
	Expensed Costs /Deferral Debt Service Requirements					$8,715,623.74
FY 2015 Conservation Resources Selected						
	2011 Conservation - 2010$$	34.6	84,552.3	38,324.6	122,876.9	
17	**2011 Conservation - 2015$$**		93,522.8	42,390.6	135,913.4	
	Capitalized Costs - Debt Service Requirements					3,966,168.77
	Expensed Costs /Deferral Debt Service Requirements					$8,750,223.14
			Principal Expense Costs	**Principal Capital Costs**	**Interest Paid Expense Costs**	**Cumulative Totals**
TOTAL Capital Costs - Debt Ser. Req. = TCC				394,638.7	159,215.3	553,854.0
TOTAL Expense Costs - Debt Serv. Req. = TEC			774,228.8		312,351.7	1,086,580.5
TOTAL DEBT SERVICE REQUIREMENTS = TDSR			774,228.8	394,638.7	471,567.0	1,640,434.5

Principal Expense Costs	774,228.8
Interest Paid Expensed Costs	312,351.7
Principal Capital Costs	394,638.7
Interest Paid Capital Costs	159,215.3
Totals	1,640,434.5

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Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018	FY 2019
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		0.0	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9
Expense		0.0	7,934.9	7,934.9	7,934.9	7,934.9	7,934.9	7,934.9	7,934.9	7,934.9	7,934.9
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		0.0	0.0	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1
Expense		0.0	0.0	8,179.7	8,179.7	8,179.7	8,179.7	8,179.7	8,179.7	8,179.7	8,179.7
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		0.0	0.0	0.0	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6
Expense		0.0	0.0	0.0	8,444.7	8,444.7	8,444.7	8,444.7	8,444.7	8,444.7	8,444.7
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		0.0	0.0	0.0	0.0	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3
Expense		0.0	0.0	0.0	0.0	8,715.6	8,715.6	8,715.6	8,715.6	8,715.6	8,715.6
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		0.0	0.0	0.0	0.0	0.0	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		0.0	0.0	0.0	0.0	0.0	8,750.2	8,750.2	8,750.2	8,750.2	8,750.2
TCC		15,481.5	19,589.4	23,867.5	28,321.1	32,957.4	36,923.6	36,923.6	36,923.6	36,923.6	36,923.6
TEC		30,413.6	38,348.5	46,528.2	54,972.9	63,688.5	72,438.7	72,438.7	72,438.7	72,438.7	72,438.7
TDSR		45,895.1	57,937.9	70,395.7	83,294.0	96,645.9	109,362.3	109,362.3	109,362.3	109,362.3	109,362.3

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Expensed costs are deferred and financed over 15-years

ALTERNATIVE - 6

Debt Service Requirements - Principal and Interest ($ 000)

Res. Stack Order		FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2011 Conservation Resources Selected											
13	**2015 Conservation - 2011$$**										
Capital		4,107.9	4,107.9	4,107.9	4,107.9	4,107.9	4,107.9				
Expense		7,934.9	7,934.9	7,934.9	7,934.9	7,934.9	7,934.9				
FY 2012 Conservation Resources Selected											
14	**2014 Conservation - 2012$$**										
Capital		4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1	4,278.1			
Expense		8,179.7	8,179.7	8,179.7	8,179.7	8,179.7	8,179.7	8,179.7			
FY 2013 Conservation Resources Selected											
15	**2013 Conservation - 2013$$**										
Capital		4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6	4,453.6		
Expense		8,444.7	8,444.7	8,444.7	8,444.7	8,444.7	8,444.7	8,444.7	8,444.7		
FY 2014 Conservation Resources Selected											
16	**2012 Conservation - 2014$$**										
Capital		4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	4,636.3	
Expense		8,715.6	8,715.6	8,715.6	8,715.6	8,715.6	8,715.6	8,715.6	8,715.6	8,715.6	
FY 2015 Conservation Resources Selected											
17	**2011 Conservation - 2015$$**										
Capital		3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2	3,966.2
Expense		8,750.2	8,750.2	8,750.2	8,750.2	8,750.2	8,750.2	8,750.2	8,750.2	8,750.2	8,750.2
TCC		36,923.6	36,923.6	36,923.6	36,923.6	36,923.6	21,442.1	17,334.2	13,056.1	8,602.5	3,966.2
TEC		72,438.7	72,438.7	72,438.7	72,438.7	72,438.7	42,025.1	34,090.2	25,910.5	17,465.8	8,750.2
TDSR		109,362.3	109,362.3	109,362.3	109,362.3	109,362.3	63,467.2	51,424.4	38,966.6	26,068.3	12,716.4

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Scenario = Capitalized costs amortized / financed over 15 years,
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ALTERNATIVE - 6

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2010 Conservation (9) Res. Selected - Total MW =		0.0								
1	**2004 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	22,723,700	1,087,612	1,137,316	1,189,291	1,243,642	1,300,476	1,359,908	1,422,056	1,487,044
	Expense Expenditures - Amort. of Principal	18,502,000	885,552	926,021	968,340	1,012,594	1,058,869	1,107,259	1,157,861	1,210,775
2	**2001 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	71,200	3,408	3,564	3,727	3,897	4,075	4,261	4,456	4,660
	Expense Expenditures - Amort. of Principal	24,855,200	1,189,631	1,243,997	1,300,848	1,360,297	1,422,462	1,487,469	1,555,446	1,626,530
4	**2006 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,438,000	786,763	822,718	860,317	899,633	940,746	983,738	1,028,695	1,075,707
	Expense Expenditures - Amort. of Principal	30,761,100	1,472,302	1,539,586	1,609,945	1,683,519	1,760,456	1,840,909	1,925,039	2,013,013
5	**2007 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	11,453,500	548,193	573,245	599,443	626,837	655,484	685,439	716,764	749,520
	Expense Expenditures - Amort. of Principal	41,499,700	1,986,278	2,077,051	2,171,972	2,271,231	2,375,026	2,483,565	2,597,064	2,715,750
6	**2003 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,500,100	1,316,222	1,376,374	1,439,274	1,505,049	1,573,830	1,645,754	1,720,965	1,799,613
	Expense Expenditures - Amort. of Principal	20,758,300	993,544	1,038,949	1,086,429	1,136,078	1,187,997	1,242,289	1,299,061	1,358,428
7	**2005 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	16,719,500	800,237	836,808	875,050	915,040	956,857	1,000,585	1,046,312	1,094,128
	Expense Expenditures - Amort. of Principal	25,443,000	1,217,765	1,273,417	1,331,612	1,392,467	1,456,102	1,522,646	1,592,231	1,664,996
8	**2002 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	34,586,600	1,655,399	1,731,051	1,810,160	1,892,884	1,979,389	2,069,847	2,164,439	2,263,354
	Expense Expenditures - Amort. of Principal	21,005,400	1,005,370	1,051,316	1,099,361	1,149,602	1,202,138	1,257,076	1,314,524	1,374,598
9	**2008 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	8,214,000	393,142	411,109	429,896	449,543	470,087	491,570	514,035	537,526
	Expense Expenditures - Amort. of Principal	65,070,900	3,114,453	3,256,783	3,405,618	3,561,255	3,724,004	3,894,191	4,072,156	4,258,254
12	**2009 Conservation - 2010$$**									
	Capital Expenditures - Amort. of Principal	27,759,600	1,328,642	1,389,361	1,452,855	1,519,250	1,588,680	1,661,283	1,737,204	1,816,594
	Expense Expenditures - Amort. of Principal	77,166,500	3,693,378	3,862,165	4,038,666	4,223,233	4,416,235	4,618,057	4,829,102	5,049,792

Scenario = Capitalized costs amortized / financed over 15 years,
= Expensed costs are deferred and amortized / financed over 15 - years

ALTERNATIVE - 6

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
FY 2010 Conservation (9) Res. Selected - Total MW =													
1	**2004 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,555,002	1,626,065	1,700,376	1,778,084	1,859,342	1,944,314	2,033,172					
	Expense Expenditures - Amort. of Principal	1,266,108	1,323,969	1,384,474	1,447,745	1,513,907	1,583,092	1,655,434					
2	**2001 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	4,873	5,095	5,328	5,572	5,826	6,093	6,365					
	Expense Expenditures - Amort. of Principal	1,700,863	1,778,592	1,859,874	1,944,870	2,033,751	2,126,693	2,223,877					
4	**2006 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,124,866	1,176,273	1,230,029	1,286,241	1,345,022	1,406,490	1,470,762					
	Expense Expenditures - Amort. of Principal	2,105,008	2,201,207	2,301,802	2,406,994	2,516,994	2,632,020	2,752,306					
5	**2007 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	783,773	819,592	857,047	896,214	937,171	980,000	1,024,778					
	Expense Expenditures - Amort. of Principal	2,839,859	2,969,641	3,105,354	3,247,268	3,395,668	3,550,850	3,713,123					
6	**2003 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,881,855	1,967,856	2,057,787	2,151,828	2,250,166	2,352,999	2,460,528					
	Expense Expenditures - Amort. of Principal	1,420,509	1,485,426	1,553,310	1,624,296	1,698,526	1,776,149	1,857,309					
7	**2005 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,144,130	1,196,417	1,251,093	1,308,268	1,368,056	1,430,576	1,495,943					
	Expense Expenditures - Amort. of Principal	1,741,086	1,820,654	1,903,858	1,990,864	2,081,847	2,176,987	2,276,468					
8	**2002 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	2,366,789	2,474,952	2,588,057	2,706,331	2,830,011	2,959,342	3,094,595					
	Expense Expenditures - Amort. of Principal	1,437,417	1,503,107	1,571,799	1,643,630	1,718,744	1,797,291	1,879,427					
9	**2008 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	562,091	587,778	614,640	642,729	672,102	702,817	734,935					
	Expense Expenditures - Amort. of Principal	4,452,858	4,656,354	4,869,151	5,091,672	5,324,362	5,567,687	5,822,102					
12	**2009 Conservation - 2010$$**												
	Capital Expenditures - Amort. of Principal	1,899,612	1,986,424	2,077,204	2,172,132	2,271,399	2,375,202	2,483,758					
	Expense Expenditures - Amort. of Principal	5,280,568	5,521,890	5,774,240	6,038,123	6,314,065	6,602,618	6,904,368					

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= Expensed costs are deferred and amortized / financed over 15 - years

ALTERNATIVE - 6

Amortization of Principal - (whole dollars)

Res. Stack Order	Vintage Year	Total Amortization of Principal	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017
FY 2011	**Conservation Resources Selected**									
13	**2015 Conservation - 2011$$**	43,905,000	0	2,101,401	2,197,436	2,297,858	2,402,870	2,512,682	2,627,511	2,747,588
	Capital Expenditures - Amort. of Principal	84,808,500	0	4,059,144	4,244,646	4,438,627	4,641,472	4,853,587	5,075,396	5,307,342
	Expense Expenditures - Amort. of Principal									
FY 2012	**Conservation Resources Selected**									
14	**2014 Conservation - 2012$$**									
	Capital Expenditures - Amort. of Principal	45,724,200	0	0	2,188,473	2,288,486	2,393,070	2,502,433	2,616,795	2,736,382
	Expense Expenditures - Amort. of Principal	87,425,400	0	0	4,184,394	4,375,621	4,575,587	4,784,691	5,003,352	5,232,005
FY 2013	**Conservation Resources Selected**									
15	**2013 Conservation - 2013$$**									
	Capital Expenditures - Amort. of Principal	47,599,900	0	0	0	2,278,249	2,382,365	2,491,239	2,605,088	2,724,141
	Expense Expenditures - Amort. of Principal	90,257,000	0	0	0	4,319,922	4,517,343	4,723,785	4,939,662	5,165,405
FY 2014	**Conservation Resources Selected**									
16	**2012 Conservation - 2014$$**									
	Capital Expenditures - Amort. of Principal	49,552,800	0	0	0	0	2,371,719	2,480,107	2,593,447	2,711,968
	Expense Expenditures - Amort. of Principal	93,153,000	0	0	0	0	4,458,532	4,662,287	4,875,353	5,098,157
FY 2015	**Conservation Resources Selected**									
17	**2011 Conservation - 2015$$**									
	Capital Expenditures - Amort. of Principal	42,390,600	0	0	0	0	0	2,028,919	2,121,640	2,218,599
	Expense Expenditures - Amort. of Principal	93,522,800	0	0	0	0	0	4,476,231	4,680,795	4,894,707
TOTALS - CAPITAL EXPENDITURES -		394,638,700								
	AMORTIZATION OF PRINCIPAL	394,638,700	7,919,618	10,382,947	13,045,922	15,920,368	19,019,648	21,917,765	22,919,407	23,966,824
TOTALS - EXPENSE EXPENDITURES -		774,228,800								
	AMORTIZATION OF PRINCIPAL	774,228,800	15,558,273	20,328,429	25,441,831	30,924,446	36,796,223	42,954,042	44,917,042	46,969,752
TOTAL CONSERVATION PRINCIPAL COSTS		1,168,867,500	23,477,891	30,711,376	38,487,753	46,844,814	55,815,871	64,871,807	67,836,449	70,936,576
PERCENTAGE OF TOTAL PRINCIPAL PAID		100.00%	2.01%	2.63%	3.29%	4.01%	4.78%	5.55%	5.80%	6.07%
CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID			2.01%	4.64%	7.93%	11.94%	16.72%	22.27%	28.07%	34.14%

PERCENTAGE OF TOTAL PRINCIPLE PAID DURING THE RATE TEST PERIOD	22.27%
TOTAL INTEREST PAID ON EXPENSED PORTION	$312,351,700
INTEREST EXPENSE - % OF EXPENSED CONSERVATION EXPENDITURES	40.34%

Scenario = Capitalized costs amortized / financed over 15 years,
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ALTERNATIVE - 6

Amortization of Principal - (whole dollars)

Row	Res. Stack Order	Vintage Year	FY 2018	FY 2019	FY 2020	FY 2021	FY 2022	FY 2023	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029
57	**FY 2011**	**Conservation Resources Selected**												
58	**13**	**2015 Conservation - 2011$$**	2,873,153	3,004,456	3,141,760	3,285,338	3,435,478	3,592,480	3,756,656	3,928,333				
59		Capital Expenditures - Amort. of Principal	5,549,887	5,803,517	6,068,738	6,346,079	6,636,095	6,939,365	7,256,494	7,588,111				
60		Expense Expenditures - Amort. of Principal												
61	**FY 2012**	**Conservation Resources Selected**												
62	**14**	**2014 Conservation - 2012$$**												
63		Capital Expenditures - Amort. of Principal	2,861,435	2,992,202	3,128,946	3,271,939	3,421,466	3,577,827	3,741,334	3,912,313	4,091,099			
64		Expense Expenditures - Amort. of Principal	5,471,107	5,721,137	5,982,593	6,255,997	6,541,897	6,840,861	7,153,489	7,480,403	7,822,266			
65	**FY 2013**	**Conservation Resources Selected**												
66	**15**	**2013 Conservation - 2013$$**												
67		Capital Expenditures - Amort. of Principal	2,848,634	2,978,817	3,114,949	3,257,302	3,406,160	3,561,822	3,724,597	3,894,811	4,072,804	4,258,922		
68		Expense Expenditures - Amort. of Principal	5,401,464	5,648,311	5,906,438	6,176,363	6,458,622	6,753,781	7,062,429	7,385,182	7,722,685	8,075,608		
69	**FY 2014**	**Conservation Resources Selected**												
70	**16**	**2012 Conservation - 2014$$**												
71		Capital Expenditures - Amort. of Principal	2,835,905	2,965,506	3,101,029	3,242,746	3,390,940	3,545,906	3,707,954	3,877,407	4,054,605	4,239,900	4,433,661	
72		Expense Expenditures - Amort. of Principal	5,331,143	5,574,776	5,829,543	6,095,953	6,374,538	6,665,855	6,970,484	7,289,035	7,622,144	7,970,476	8,334,724	
73	**FY 2015**	**Conservation Resources Selected**												
74	**17**	**2011 Conservation - 2015$$**												
75		Capital Expenditures - Amort. of Principal	2,319,989	2,426,013	2,536,881	2,652,817	2,774,051	2,900,825	3,033,392	3,172,018	3,316,980	3,468,566	3,627,079	3,792,831
76		Expense Expenditures - Amort. of Principal	5,118,395	5,352,306	5,596,906	5,852,685	6,120,153	6,399,844	6,692,316	6,998,155	7,317,971	7,652,402	8,002,117	8,367,817
77														
78	TOTALS - CAPITAL EXPENDITURES -													
79		AMORTIZATION OF PRINCIPAL	25,062,107	26,207,446	27,405,126	28,657,541	29,967,190	31,336,693	32,768,769	18,784,882	15,535,488	11,967,388	8,060,740	3,792,831
80	TOTALS - EXPENSE EXPENDITURES -													
81		AMORTIZATION OF PRINCIPAL	49,116,272	51,360,887	53,708,080	56,162,539	58,729,169	61,413,093	64,219,626	36,740,886	30,485,066	23,698,486	16,336,841	8,367,817
82														
83	TOTAL CONSERVATION PRINCIPAL COSTS		74,178,379	77,568,333	81,113,206	84,820,080	88,696,359	92,749,786	96,988,395	55,525,768	46,020,554	35,665,874	24,397,581	12,160,648
85	PERCENTAGE OF TOTAL PRINCIPAL PAID		6.35%	6.64%	6.94%	7.26%	7.59%	7.94%	8.30%	4.75%	3.94%	3.05%	2.09%	1.04%
87	CUMULATIVE PERCENTAGE OF TOTAL PRINCIPAL PAID		40.49%	47.13%	54.07%	61.33%	68.92%	76.86%	85.16%	89.91%	93.85%	96.90%	98.99%	100.03%

APPENDIX C

Non - Conservation Resources

Documentation of the Annual Amounts of Non - Conservation Resources Available

AND

Documentation of Projected Resource Costs

Section 7(b)(2) Rate Test Study and Documentation

WP-10 Initial Rate Proposal
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Section 7(b)(2) Rate Test Study and Documentation
Summary of Non - Conservation Resources
WP-10 Initial Rate Proposal

Name of Resource	Amount MW	Projected Annual Generation MWh	Capital Investment 2010 $$ ($ 000)	Capital Investment 2015 $$ ($ 000)	Annual O & M ($ 000)	Remaining Useful Life	Annual Capital Cost ($ 000)	Cost Per MWh $ / MWh FY 2010
Resources Included in the 7(b)(2) Resource Stack:								
Billing Credits	10.14	88,833	------	------	$5,267.8	30	0.0	$59.30
Boardman Coal Plant	49.71	435,453	$65,850.9	$113,982.8	$16,103.6	30	0.0	$36.98
Cowlitz Falls Hydro Project	26.00	227,760	$194,980.2		$3,597.7	60	11,620.5	$66.82
Idaho Falls Hydro Project	18.50	162,060	------	------	$6,115.4	60	0.0	$37.74
Wauna Cogeneration	21.70	190,000	------	------	$11,463.5	30	0.0	$60.33
Other Resources NOT Included in the 7(b)(2) Resource Stack - Non-Dedicated Portions:								
Nine Canyon Wind Project	13.52	118,459	------	------	$8,751.0	20	0.0	$73.88
Priest Rapids Hydro	14.90	130,524	$10,644.7	$17,787.9	$2,931.8	70	0.0	$22.46
Wanapum Hydro	14.80	129,648	$19,084.7	$28,227.6	$3,712.9	70	0.0	$28.64

WP-10 Power Rate Case

Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts

Forecasted Cost of Resource During FY2010

Billing Credit Summary - 7(b)(2) Case

BPA Billing Credits - 7(b)(2) Case Costs - 2010$$

Summary:	Average aMW	Total MWh/Year	Cost Per MWh	Annual Cost
Project A - South Fork Tolt Hydro Project	6.5468	57,350	$59.4976	3,412,189
Project B - Wynochee Hydro Project	3.5939	31,483	$58.9409	$1,855,637
	10.1408	88,833	$59.30	$5,267,826
Annual Cost Data	10.1408	88,833	$59.30	$5,267,826

Estimated remaining useful life = 30 years

Notes:

Note 1 - The Program Case Revenue requirement includes the Smith Creek Hydro Project for the years of FY2010-2011 and the Short Mountain Landfill Project for the years FY 2010-2012. The Smith Creek Hydro Project contract terminates on September 30, 2011 and the Short Mountain landfill Project terminates on July 31, 2012. Because these resources are not available to serve 7(b)(2) Customer loads during all years of the rate test period (FY 2010-2015) they were omitted from the 7(b)(2) Case resource stack. The costs and the average hourly energy amounts are not comparable between the Program Case and the 7(b)(2) Case due to the expiration of these power purchase contracts.

Note 2 - Billing Credit Amounts for the Program Case:

	2010	2011	2012	2013	2014	2015
Average Hourly Energy - aMW	17.5	17.5	11.8	10.1	10.1	10.1
Annual Revenue Requirement Costs	$7,383,000	$7,469,000	$5,873,000	$5,685,000	$5,749,967	$5,815,676

Note 3 - The cost of the two billing credit resources contained in the resource stack was based on the alternative cost value average for FY2010-2015 per the applicable contract schedule. Because this amount is an average of the entire six year rate test period, the cost of the resource would be overstated if this average cost amount was escalated by the rate models escalation cost factors. For this reason the annual cost amount is entered in the "Annual Capital Cost' column in the 2010 Rate Model's resource Sort tab, this annual cost amount does not escalate once it is chosen from the resource stack.

Note 4 - The cost paid for billing credits as determined by the applicable contract provisions is dependent on the level of BPA's power and transmission rates during the rate test period. This spread sheet used a projected percentage cost escalation amount of 7.5% for BPA's 2010-2011 Power Rates over the level of BPA's 2007-2009 power rates. Based on the TS-10 Partial Settlement Offer being worked out between BPA and the rate case parties, it was assumed that there would be a 0% percentage increase for BPA's 2010-2011 Transmission Rates over the level of BPA's 2008-2009 transmission rates.

WP-10 Power Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2010

Project A - South Fork Tolt Hydro Project - Billing Credit Detail

Projected FY 2010-2015 Power Rate Increase over FY2007-2009 Power Rates = 1.0750
Projected FY 2010-2015 Transmission Rate Increase over FY2007-2009 Power Rates = 1.0000

NERC FY 2010 Hourly Amounts:

Month	Hours	HLH	LLH	Projected 2010-2011 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Demand kW	Alternative Cost $/MWh /5	PF Power Only $	Projected PTP-10 plus Load Shaping 1.501	Alternative Cost Value $	Cost of PF Power plus Tx $	Billing Credit $
October	744	432	312	31.93	23.39	2.09	0.51	4085	0	11,200	97.75	155,845	22,515	399,309	178,360	220,948
November	721	384	337	34.06	24.83	2.24	0.51	3966	0	11,200	97.75	162,113	22,515	387,677	184,628	203,048
December	744	416	328	35.54	26.08	2.34	0.51	4136	0	11,200	97.75	175,328	22,515	404,294	197,843	206,451
January	744	400	344	30.18	21.82	1.99	0.51	4158	0	11,300	97.75	150,042	22,515	406,445	172,557	233,887
February	672	384	288	30.81	22.04	2.02	0.51	3783	0	11,300	97.75	141,301	22,515	369,788	163,816	205,972
March	743	432	311	28.58	20.95	1.88	0.51	4180	0	11,300	97.75	142,852	22,515	408,595	165,367	243,228
April	720	416	304	26.82	19.27	1.76	0.51	4060	0	11,300	97.75	130,867	22,515	396,865	153,382	243,483
May	744	400	344	22.40	15.49	1.46	0.51	4933	0	12,300	97.75	130,989	22,515	482,201	153,504	328,697
June	720	416	304	20.29	10.77	1.34	0.51	5710	0	13,600	97.75	136,989	22,515	558,153	159,504	398,649
July	744	416	328	24.98	18.29	1.64	0.51	6993	0	15,000	97.75	202,911	22,515	683,566	225,426	458,140
August	744	416	328	29.25	21.69	1.92	0.51	6702	0	14,700	97.75	227,711	22,515	655,121	250,226	404,894
September	720	400	320	30.20	24.23	1.99	0.51	4644	0	12,100	97.75	166,644	22,515	453,951	189,159	264,792
	8,760	4,912	3,848					57,350	0	146,500		1,923,593	270,180	5,605,963	2,193,773	3,412,189

Average aMW **6.5468** **Annual Cost per MWh** **59.4976**

Note 5 - Alternative cost value is the average of FY2010-2015 contract schedule, Exhibit C, Table 3.

Project A - South Fork Tolt Hydro Project

NERC FY 2010 Values:

Month	Hours	HLH	LLH	Final 2007-2009 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Demand kW	Alternative Cost $/MWh /6	PF Power Only $	PTP-08 (1.298/kw/month) plus Ld shaping $0.203 1.501	Alternative Cost Value $	Cost of PF Power plus Tx $	Billing Credit $
October	744	432	312	29.70	21.76	1.94	0.47	4085	0	11200	96.7	143,053	22,515	395,020	165,568	229,452
November	721	384	337	31.68	23.10	2.08	0.47	3966	0	11200	96.7	148,939	22,515	383,512	171,454	212,058
December	744	416	328	33.06	24.26	2.18	0.47	4136	0	11200	96.7	161,152	22,515	399,951	183,667	216,284
January	744	400	344	28.07	20.30	1.85	0.47	4158	0	11300	96.7	137,620	22,515	402,079	160,135	241,944
February	672	384	288	28.66	20.50	1.88	0.47	3783	0	11300	96.7	129,665	22,515	365,816	152,180	213,636
March	743	432	311	26.59	19.49	1.75	0.47	4180	0	11300	96.7	130,921	22,515	404,206	153,436	250,770
April	720	416	304	24.95	17.93	1.64	0.47	4060	0	11300	96.7	119,829	22,515	392,602	142,344	250,258
May	744	400	344	20.84	14.41	1.36	0.47	4933	0	12300	96.7	119,532	22,515	477,021	142,047	334,974
June	720	416	304	18.87	10.02	1.25	0.47	5710	0	13600	96.7	124,748	22,515	552,157	147,263	404,894
July	744	416	328	23.24	17.01	1.53	0.47	6993	0	15000	96.7	185,467	22,515	676,223	207,982	468,241
August	744	416	328	27.21	20.18	1.79	0.47	6702	0	14700	96.7	208,674	22,515	648,083	231,189	416,894
September	720	400	320	28.09	22.54	1.85	0.47	4644	0	12100	96.7	152,835	22,515	449,075	175,350	273,725
	8,760	4,912	3,848					57,350	0	146,500		1,762,435	270,180	5,545,745	2,032,615	3,513,130

Average aMW **6.5468** **Annual Cost per MWh** **61.2577**

Note 6 - Alternative cost value is contract schedule amount for FY 2009, Exhibit C, Table 3.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T

WP-10 Power Rate Case

Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts

Forecasted Cost of Resource During FY2010

Project B - Wynochee Hydro Project - Billing Credit Detail

Projected FY 2010 Power Rate Increase over FY2007-2009 Power Rates = 1.0750

Projected FY 2010 Transmission Rate Increase over FY2007-2009 Power Rates = 1.0000

Row	NERC FY 2010 Values: Month	Hours	HLH	LLH	Projected 2010-2011 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Assured Energy Capabilities	Demand kW	Alternative Cost $/MWh /7	Alternative Cost Value $	Projected PTP-10 plus Load Shaping 1.501	PF Power Costs Only $	**PF Power Plus Tx** $	**Billing Credit** $
102																		
103	October	744	432	312	31.93	23.39	2.09	0.51	2,122	1,532	3,654	4,910	93.8	342,745	10,567	115,670	126,237	216,508
104	November	721	384	337	34.06	24.83	2.24	0.51	2,242	1,967	4,209	5,850	93.8	394,804	10,567	140,403	150,970	243,834
105	December	744	416	328	35.54	26.08	2.34	0.51	2,929	2,310	5,239	7,040	93.8	491,418	10,567	183,487	194,054	297,364
106	January	744	400	344	30.18	21.82	1.99	0.51	2,569	2,210	4,779	6,420	93.8	448,270	10,567	140,933	151,500	296,770
107	February	672	384	288	30.81	22.04	2.02	0.51	2,415	1,812	4,227	6,290	93.8	396,493	10,567	129,188	139,755	256,737
108	March	743	432	311	28.58	20.95	1.88	0.51	1,425	1,026	2,451	3,290	93.8	229,904	10,567	69,657	80,224	149,679
109	April	720	416	304	26.82	19.27	1.76	0.51	1,117	816	1,933	2,680	93.8	181,315	10,567	51,388	61,955	119,361
110	May	744	400	344	22.40	15.49	1.46	0.51	0	0	0	0	93.8	-	10,567	-	10,567	(10,567)
111	June	720	416	304	20.29	10.77	1.34	0.51	0	0	0	0	93.8	-	10,567	-	10,567	(10,567)
112	July	744	416	328	24.98	18.29	1.64	0.51	1,006	793	1,799	2,420	93.8	168,746	10,567	44,522	55,089	113,657
113	August	744	416	328	29.25	21.69	1.92	0.51	912	719	1,631	2,190	93.8	152,988	10,567	47,312	57,879	95,109
114	September	720	400	320	30.20	24.23	1.99	0.51	867	694	1,561	2,170	93.8	146,422	10,567	48,102	58,669	87,753
115		8,760	4,912	3,848					17,604	13,879	31,483	43,260		2,953,105	126,804	970,664	1,097,468	1,855,637
116																		
117								**Average aMW**	**3.5939**						**Annual Cost per MWh**			**$58.9409**

Note 7 - Alternative cost value is the average of FY2010-2015 contract schedule, Exhibit C, page 10, Table 3.

Project B - Wynochee Hydro Project

Row	NERC FY 2010 Values: Month	Hours	HLH	LLH	Final 2007-2009 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Load Variance $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Assured Energy Capabilities	Demand kW	Alt Cost $/MWh /8	**AC$** $	PTP-08 (1.298/kw/month) plus Ld shaping $0.203 1.501	PF Power Costs Only $	**PF Power Plus Tx** $	**Billing Credit** $
125	October	744	432	312	29.70	21.76	1.94	0.47	2,122	1,532	3,654	4,910	91.5	334,341	9,636	105,883	115,519	218,822
126	November	721	384	337	31.68	23.10	2.08	0.47	2,242	1,967	4,209	5,850	91.5	385,124	9,636	128,630	138,266	246,858
127	December	744	416	328	33.06	24.26	2.18	0.47	2,929	2,310	5,239	7,040	91.5	479,369	9,636	168,223	177,860	301,509
128	January	744	400	344	28.07	20.30	1.85	0.47	2,569	2,210	4,779	6,420	91.5	437,279	9,636	128,855	138,491	298,787
129	February	672	384	288	28.66	20.50	1.88	0.47	2,415	1,812	4,227	6,290	91.5	386,771	9,636	118,189	127,825	258,945
130	March	743	432	311	26.59	19.49	1.75	0.47	1,425	1,026	2,451	3,290	91.5	224,267	9,636	63,646	73,282	150,985
131	April	720	416	304	24.95	17.93	1.64	0.47	1,117	816	1,933	2,680	91.5	176,870	9,636	46,894	56,531	120,339
132	May	744	400	344	20.84	14.41	1.36	0.47	0	0	0	0	91.5	-	9,636	-	9,636	(9,636)
133	June	720	416	304	18.87	10.02	1.25	0.47	0	0	0	0	91.5	-	9,636	-	9,636	(9,636)
134	July	744	416	328	23.24	17.01	1.53	0.47	1,006	793	1,799	2,420	91.5	164,609	9,636	40,570	50,207	114,402
135	August	744	416	328	27.21	20.18	1.79	0.47	912	719	1,631	2,190	91.5	149,237	9,636	43,245	52,881	96,355
136	September	720	400	320	28.09	22.54	1.85	0.47	867	694	1,561	2,170	91.5	142,832	9,636	44,013	53,649	89,183
137		8,760	4,912	3,848					17,604	13,879	31,483	43,260		2,880,695	115,637	888,146	1,003,783	1,876,911
138																		
139								**Average aMW**	**3.5939**						**Annual Cost per MWh**			**$59.6167**

Note 8 - Alternative cost value is the FY2009 contract schedule value, Exhibit C, page 10, Table 3.

Determination of Adjusted Alternative Cost

TABLE 3
(continued)

DERIVATION OF ADJUSTED ALTERNATIVE COST - SOUTH FORK TOLT HYDRO PROJECT

Adjusted Alternative Cost Stream 1/
(nominal mills/kWh)

2/ Year	Fixed	Variable	Total	2/ Year	Fixed	Variable	Total
1996	82.9	6.6	89.5	2021	82.9	22.4	105.3
1997	82.9	6.9	89.9	2022	82.9	23.5	106.4
1998	82.9	7.3	90.2	2023	82.9	24.7	107.6
1999	82.9	7.7	90.6	2024	82.9	25.9	108.8
2000	82.9	8.0	91.0	2025	82.9	27.2	110.1
2001	82.9	8.4	91.4	2026	82.9	28.6	111.5
2002	82.9	8.9	91.8	2027	82.9	30.0	112.9
2003	82.9	9.3	92.2	2028	82.9	31.5	114.4
2004	82.9	9.8	92.7	2029	0.0	0.0	0.0
2005	82.9	10.3	93.2	2030	0.0	0.0	0.0
2006	82.9	10.8	93.7	2031	0.0	0.0	0.0
2007	82.9	11.3	94.2	2032	0.0	0.0	0.0
2008	82.9	11.9	94.8	2033	0.0	0.0	0.0
2009	82.9	12.5	95.4	2034	0.0	0.0	0.0
2010	82.9	13.1	96.0	2035	0.0	0.0	0.0
2011	82.9	13.7	96.7	2036	0.0	0.0	0.0
2012	82.9	14.4	97.3	2037	0.0	0.0	0.0
2013	82.9	15.1	98.1	2038	0.0	0.0	0.0
2014	82.9	15.9	98.8	2039	0.0	0.0	0.0
2015	82.9	16.7	99.6	2040	0.0	0.0	0.0
2016	82.9	17.5	100.5	2041	0.0	0.0	0.0
2017	82.9	18.4	101.3	2042	0.0	0.0	0.0
2018	82.9	19.3	102.3	2043	0.0	0.0	0.0
2019	82.9	20.3	103.2	2044	0.0	0.0	0.0
2020	82.9	21.3	104.2	2045	0.0	0.0	0.0

Average of six years = 97.75

1/ This table derived from the levelized Adjusted Alternative Cost using the Variable/Total Cost Fraction and assumes 5 percent annual inflation and a 3 percent real discount rate.
2/ Year = Calendar Year.

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Revision No. 1
Exhibit C, Page 10 of 11
Contract No. DE-MS79-92BP93649
Procurement No. 76520
City of Tacoma
Effective at 0001 hours
on August 1, 1993

Determination of Adjusted Alternative Cost

TABLE 3
(continued)

DERIVATION OF ADJUSTED ALTERNATIVE COST - WYNOOCHEE HYDRO PROJECT

Adjusted Alternative Cost Stream 1/
(nominal mills/kWh)

Year 2/	Fixed	Variable	Total	Year 2/	Fixed	Variable	Total
1994	79.4	5.8	85.2	2015	79.4	16.2	95.6
1995	79.4	6.1	85.5	2016	79.4	17.1	96.4
1996	79.4	6.4	85.8	2017	79.4	17.9	97.3
1997	79.4	6.8	86.1	2018	79.4	18.8	98.2
1998	79.4	7.1	86.5	2019	79.4	19.7	99.1
1999	79.4	7.4	86.8	2020	79.4	20.7	100.1
2000	79.4	7.8	87.2	2021	79.4	21.8	101.2
2001	79.4	8.2	87.6	2022	79.4	22.9	102.2
2002	79.4	8.6	88.0	2023	79.4	24.0	103.4
2003	79.4	9.0	88.4	2024	79.4	25.2	104.6
2004	79.4	9.5	88.9	2025	79.4	26.5	105.8
2005	79.4	10.0	89.4	2026	79.4	27.8	107.2
2006	79.4	10.5	89.9	2027	79.4	29.2	108.6
2007	79.4	11.0	90.4	2028	79.4	30.6	110.0
2008	79.4	11.5	90.9	2029	79.4	32.2	111.6
2009	79.4	12.1	91.5	2030	79.4	33.8	113.2
2010	79.4	12.7	92.1	2031	79.4	35.5	114.8
2011	79.4	13.4	92.7	2032	79.4	37.2	116.6
2012	79.4	14.0	93.4	2033	79.4	39.1	118.5
2013	79.4	14.7	94.1	2034	79.4	41.1	120.4
2014	79.4	15.5	94.9	2035	79.4	43.1	122.5
2015	79.4	16.2	95.6				

Average of 6 years = 93.8

1/ This table derived from the levelized Adjusted Alternative Cost using the Variable/Total Cost ratio and assumes 5 percent annual inflation and a 3 percent real discount rate.
2/ Year = Calendar Year.

BPA-TS Transmission Rates Partial Settlement Offer
Summary for AE/CAT Meeting
As of January 9, 2009

The following is in the perspective of BPA-PS as a Transmission Customer (TC) of BPA-TS, so the BPA-TS perspective is not necessarily represented.

BPA has been holding Transmission and Power Rates Workshops for several months. BPA-TS has proposed a Transmission Rates Partial Settlement, and asked parties to returned signed copies by Jan. 16, 2009 so they may determine whether there is sufficient agreement prior to the Transmission Rates Initial Proposal (February 2009).

Partial Settlement summary:

- Rates stay at WT-08 levels for the base transmission rates, including Network Integration (NT), Point-to-Point (PTP) for the Network and Southern Intertie segments. Power Factor Penalty Charge, Utility Delivery Charge, Scheduling Control and Dispatch, and Generation Supplied Reactive also remained unchanged.
- The following were not included in the settlement: Regulation and Frequency Response, Energy Imbalance, Operating Reserves for Spinning and Supplemental, Generation Imbalance, and Control Area Services. The issues that are not included in the partial settlement will be litigated as part of the rate case.
    - Ancillary Services and Control Area Services will be part of the Transmission docket.
    - Generation Inputs are part of the Power Rates docket.
    - The Wind Integration Rate Case settlement put into place the BPA Wind Integration Team (WIT). The WIT is working on operational and reliability issues.
- To address customers' requests, the settlement includes BPA's plan to hold review and discussions on rate design for future rate periods, for rates such as Utility Delivery Charge (for low voltage service) and the Northern Intertie segment (as separate from the Network segment of PTP).
- The Failure to Comply (FTC) rate increased from $100 to $1,000/MW, and includes a new provision that states that those assessed the FTC will be assessed other costs to manage the situation and/or monetary penalties imposed on BPA that results from the customer's non-compliance, to the extent that the customer's non-compliance contributed to the problem.
- To address customer concerns about the increase in the FTC rate, BPA-TS will hold a public business practice process for implementing this new charge. BPA-TS included the provision that the new FTC rate will not be assessed until the business practice process is completed.
- Unauthorized Increase Charge (UIC) increased from twice the rate of the transmission purchase (which varies), to the lower of $100/MWh plus the FERC price cap for WECC spot market, or $1,000/MWh. If FERC eliminates this price cap, the charge will be $500/MWh.
- An updated "Procedures for Redispatch" (Attachment M, formerly referred to as Attachment K) is included. No substantive change.

On a separate note, BPA-PS submitted comments recommending that the Generation and Energy Imbalance rates schedules clarify that when (1) during the Spill Condition and Intentional Deviation situations, and (2) the BPA Incremental Cost is negative (due to negative Mid-C prices), BPA will not pay customers when imbalance energy is delivered to Customers. This is not part of the partial settlement, and is expected to be addressed in the Transmission Rate Case process.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Cost Projections -10% Interest in Boardman Coal Plant

SUMMARY

7(b)(2) Case - Resource Stack Values:

		FY2010-$$
Total Annual Operating and Maintenance (O & M) / Production Expenses:		16,103,582
Debt Service - Included in O&M Amount Above		0
Total Operating and Financing Costs - (Production and Debt Service)		16,103,582
Cost per MWh		**$36.98**
	100.00%	**10.00%**
Projected Capital Investment - as of FY 2010	658,508,594	65,850,859
Projected Capital Investment - as of FY 2015	1,139,828,277	113,982,828
Depreciable Life at beginning placed in service date -1980	60 years	
Estimated remaining useful life at FY 2010	30 years	
Placed in service	1980	
	100.00%	**10.00%**
Plants Name Plate Rating (MW)	642	64.2
Net Continuous Plant Capability (MW)	585	58.50
Projected Net Annual Generation - MWh - Based on PGE's		
2007 FERC Form 1 Amounts	4,354,531	435,453
Projected Capacity Factor	77.43%	77.43%
Projected Average Hourly Generation - aMW	497.09	49.71

Page 1 of 2

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Cost Projections -10% Interest in Boardman Coal Plant
SUMMARY

	BPA's Projected Boardman Operating 100% Budget **FY 2010**	BPA's Projected Boardman Operating 100% Budget **FY 2011**	BPA's Projected Boardman Operating 100% Budget **FY 2012**	BPA's Projected Boardman Operating 100% Budget **FY 2013**	BPA's Projected Boardman Operating 100% Budget **FY 2014**	BPA's Projected Boardman Operating 100% Budget **FY 2015**
1. Total Production Expenses - 100% See Production Analysis	105,276,294	107,490,627	109,081,119	110,674,143	131,867,068	133,895,077
2. 2010$$ Price Conversion Factor	1.000000	1.020232	1.041582	1.062788	1.084313	1.106094
PRC's Projected Operating Costs						
3. PRC's 10% Share of Production Expenses (line 1 times 10%)	10,527,629	10,749,063	10,908,112	11,067,414	13,186,707	13,389,508
PRC's 10% Debt Service Costs - See Debt Service Analysis	3,835,826	4,193,794	4,271,583	4,350,940	7,565,520	7,648,170
4. PRC's Projected Total Operating Costs - Nominal $$	14,363,455	14,942,857	15,179,695	15,418,354	20,752,227	21,037,678
Average Annual Operating Costs - Nominal $$	16,949,044					
5. Projected Annual Amounts Stated in 2010$$ (line 4 divided by line 2)	14,363,455	14,646,528	14,573,692	14,507,460	19,138,594	19,019,792
6. FY 2010 -2015 Average Total Operating Costs in 2010$$	16,041,587	16,041,587	16,041,587	16,041,587	16,041,587	16,041,587
7. Operating Cost Adjustment - See Note A below	61,995	61,995	61,995	61,995	61,995	61,995
8. Adjusted Annual Cost Amount in 2010 $$	16,103,582	16,103,582	16,103,582	16,103,582	16,103,582	16,103,582
Ram Model Annual Cost Amounts Using Average Cost Pricing 9. (line 8 times line 2)	16,103,582	16,429,390	16,773,201	17,114,694	17,461,323	17,812,075
Annual Variance Over / (Under) (line 9 less line 4)	1,740,127	1,486,533	1,593,506	1,696,339	(3,290,904)	(3,225,602)
Total of Annual Variances =	(1)					

Note A - It is necessary to make an operating adjustment so that the average total operating costs for all years of the rate test period (FY2010-2015) is equivalent to the total actual operating costs in nominal dollars (line 4) since the RAM model starts with a beginning cost of when the resource is selected from the resource stack and then escalates the cost using the fixed escalation factors at line 2 above. If a simple average of the nominal operating costs for the rate test period were used, the "starting operating cost" of the resource would have been higher at a rate of $16,878,712 in comparison to the adjusted operating cost amount of $16,036,758.

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WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Production Cost Projections -10% Interest in Boardman Coal Plant

Boardman Operating Cost Historical Data OY2007 / PGE Operating Budgets 2008-2009 / FY 2010-2015 BPA Projections:

	PGE's FERC Form No. 1 Data Page 402 OY 2007 - 1/	Portland General Electric's Boardman 100% Budget OY 2008 - 2/	Portland General Electric's Boardman 100% Budget OY 2009 - 3/	BPA's Projected Boardman Operating 100% Budget OY 2010	BPA's Projected Boardman Operating 100% Budget OY 2011	BPA's Projected Boardman Operating 100% Budget OY 2012	BPA's Projected Boardman Operating 100% Budget OY 2013	BPA's Projected Boardman Operating 100% Budget OY 2014	BPA's Projected Boardman Operating 100% Budget OY 2015
Cumulative price deflator Index to convert 2009$$ to respective year $$:				1.020573	1.041221	1.063010	1.084652	1.106620	1.128849
Fuel Cost - FERC # 501 - See Note 5		1,864,722	1,837,111	1,892,224	1,948,991	2,007,461	2,067,685	2,129,715	2,193,607
Fuel Oil Costs			0	0	0	0	0	0	0
Fuel Inventory Oil Purchase - See Note 5		813,962	1,269,066	1,041,514	1,072,759	1,104,942	1,138,090	1,172,233	1,207,400
Payroll Taxes #408		1,016,802	1,016,802	1,037,720	1,058,716	1,080,871	1,102,877	1,125,214	1,147,816
Other Misc. Electric Revenues #456		(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)	(600,000)
Fuel Inventory - Coal fixed O&M #151 - See Note 4		1,930,798	1,601,966	1,617,505	1,633,195	1,649,037	1,665,033	1,681,183	1,697,491
Coal Fuel Costs #151- see Note 4	61,041,164	62,346,284	59,460,450	60,037,216	60,619,577	61,207,587	61,801,301	62,400,773	63,006,061
TOTAL FUEL COSTS	61,041,164	67,372,568	64,585,395	65,026,180	65,733,238	66,449,898	67,174,985	67,909,119	68,652,375
Operating Cost Data:									
Production Expenses - line 19	6,763,843	7,086,196	7,081,771	7,227,462	7,373,688	7,527,995	7,681,260	7,836,831	7,994,253
Incremental Production Expenses - new pollution controls-see Note 6			0	0	0	0	0	12,378,690	12,627,345
Misc. Steam / Power Expenses FERC #506 & #557- line 26	2,169,128	2,266,495	2,150,974	2,195,225	2,239,639	2,286,507	2,333,059	2,380,311	2,428,126
Rent Expense #507- line 27	0	0	0	0	0	0	0	0	0
Allowances - line 28	0	0	0	0	0	0	0	0	0
Administrative & General Expenses #921-#930		5,953,214	5,810,950	5,930,497	6,050,483	6,177,099	6,302,861	6,430,515	6,559,687
TOTAL OPERATION COSTS	8,932,971	15,305,905	15,043,695	15,353,184	15,663,810	15,991,601	16,317,180	29,026,347	29,609,410
Maintenance Expense -									
Base Amount line - 29	19,406,261	18,902,363	24,395,046	24,896,918	25,400,633	25,932,182	26,460,146	26,996,052	27,538,332
Incremental Costs Pollution Controls - See Note 6		0	0	0	692,944	707,445	721,849	7,935,562	8,094,967
TOTAL MAINTENANCE EXPENSES	19,406,261	18,902,363	24,395,046	24,896,918	26,093,577	26,639,627	27,181,994	34,931,614	35,633,299
Total Production Expenses	89,380,396	101,580,836	104,024,136	105,276,283	107,490,625	109,081,126	110,674,160	131,867,080	133,895,084

Notes:

Note 1 - PGE's 2007 FERC FORM No. 1 data for Boardman's 2007 operations can be found at Attachment A.

Note 2 - PGE's 2008 Boardman operating budget can be found at Attachment B.

Note 3 - PGE's 2009 Boardman operating budget can be found at Attachment C.

Note 4 - Extended outage planned for OY 2009, new fixed price coal contract signed June of 2008 accounts for decreased coal fuel costs for OY 2009. Coal expense for FY 2010-2015 was calculated using the average price increase information for FY 2010-2013 contained on the March 2008 # DOE/EIA-0383e web site. This annual average increase amount of 0.97% was used to inflate the cost of fuel used to in Boardman's operations.

1 **WP-10 Wholesale Power Rate Case**

2 **Section 7(b)(2) Resource Stack**

3 **Production Cost Projections -10% Interest in Boardman Coal Plant**

54 **Notes - Continued:**

55 **Note 5** - Fuel Oil inventory costs for FY2010 assumes the average of FY2008 and FY2009 amounts. Fuel oil costs for FY 2011-2015 are escalated at an annual rate of 3.0%.

56 **Note 6** - Based on the information contained in PGE's Best Available Retrofit Technology (BART) Analysis Report (see PGE web site) there are four main areas of pollution
57 controls that PGE has identified as meeting BART. These are presented below in chronological order of projected installation by the BPA analyst. The costs are based
58 on information contained in Appendix D - Cost Analysis Summary to the BART report and are displayed below by total 1) Capital Investment Costs, 2) Direct Variable
59 Annual Production expenses, and 3) Direct Variable Annual Maintenance costs. The Executive Summary and Exhibit D to the BART Report can be found at Attachment E.
60 The projected debt service costs associated with PRC's 10% share of the capital investments are presented in the financing of capital additions analysis. The costs presented
61 below are presented in 2007$$ based on the information contained in Appendix D to the Bart Report as referenced. The implementation of the measures was informed by PGE's
62 letter to the Oregon Department of Environmental Quality regarding proposed regional haze rules dated December 17, 2008 (See Attachment D).

Row	B	H	I	J	K	L
64		OY 2011	OY 2012	OY 2013	OY 2014	OY 2015
65	Cumulative price deflator Index to convert 2007$$ to respective year $$:	1.089535	1.112335	1.134982	1.157969	1.181230
67	A. - Installation of New Low Nox Burners (NLNB) and Modified Over Fire Air (MOFA) System:					
68	1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-5)	32,651,000				
69	2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-5)	0				
70	3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-5)	636,000				
71	1b) Capital costs in 2011 $$	35,574,412	0	0	0	0
72	2b) Direct Variable Annual Production expenses in 2011-2015 $$	0	0	0	0	0
73	3b) Direct Variable Annual Maintenance costs in 2011-2015 $$	692,944	707,445	721,849	736,468	751,262
75	B. - Installation of Particulate Control Measure - Pulse Jet Fabric Filter (PJFF) System					
76	1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-12)	94,353,000				
77	2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-12)	2,121,000				
78	3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-12)	1,808,000				
79	1b) Capital costs in 2014 $$	0	0	0	109,257,858	
80	2b) Direct Variable Annual Production expenses in 2014-2015 $$	0	0	0	2,456,052	2,505,388
81	3b) Direct Variable Annual Maintenance costs in 2014-2015 $$	0	0	0	2,093,608	2,135,663
83	C. - Installation of SO_2 Pollution Controls - Semi-Dry Flue Gas Desulfurization (FGD) System					
84	1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-11)	247,293,000				
85	2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-11)	8,569,000				
86	3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-11)	4,409,000				
87	1b) Capital costs in 2014 $$	0	0	0	286,357,652	0
88	2b) Direct Variable Annual Production expenses in 2014-2015 $$	0	0	0	9,922,637	10,121,957
89	3b) Direct Variable Annual Maintenance costs in 2014-2015 $$	0	0	0	5,105,486	5,208,042
91	Either D. or E. would be installed by 2017 which is outside of the rate test period.					
93	D. - Selective Non-Catalytic Reduction (SNCR) System					
94	1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-6)	17,429,000				
95	2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-6)	3,398,000				
96	3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-6)	343,000				
98	E. - Selective Catalytic Reduction (SCR) System					
99	1a) Capital costs in 2007$$ - (BART Report, Appendix D, page D-6)	190,859,000				
100	2a) Direct Variable Annual Production expenses in 2007$$ - (BART Report, Appendix D, page D-6)	2,927,000				
101	3a) Direct Variable Annual Maintenance costs in 2007$$ - (BART Report, Appendix D, page D-6)	2,746,000				
103		OY 2011	OY 2012	OY 2013	OY 2014	OY 2015
104	SUMMARY - CAPITAL COSTS BY YEAR	35,574,412	0	0	395,615,511	0
105	SUMMARY - DIRECT VARIABLE ANNUAL PRODUCTION COSTS BY YEAR	0	0	0	12,378,690	12,627,345
106	SUMMARY - DIRECT ANNUAL MAINTENANCE COSTS BY YEAR	692,944	707,445	721,849	7,935,562	8,094,967

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Cost Projections -10% Interest in Boardman Coal Plant
Analysis of Coal Fuel Cost

	2006	2007	2008
Oil Price Escalation			
Inflations Rate		2.00%	2.00%
Inflation Factor	100.0%	102.0%	104.0%
Coal ($2006) - Delivered Price -	33.85	34.52	35.23
March 2008 # DOE/EIA-0383			
Coal Nominal	$ 33.85	$ 35.21	$ 36.65
Percentage Change in Coal Price (Nominal)		4.02%	4.10%

		Historical - FERC Form No. 1				PGE Budget
		2004	2005	2006	2007	2008
Net Continuous Plant Capability (MW)	**FERC Form 1, Page 402**	568	585	585	585	585
Hours Connected to load	**FERC Form 1, Page 402**	6,449	6,235	4,357	6,686	
Capacity Factor		71.14%	69.49%	47.11%	84.98%	84.98%
Fuel	**FERC Form 1, Page 402**	$ 44,256,851	$ 47,834,482	$ 35,492,843	$ 61,041,164	$ 62,346,284
Fuel Burned						
Quantity Coal (tons)	**FERC Form 1, Page 402**	2,119,299	2,103,125	1,435,147	2,577,187	2,586,135
Average Heat Content - Coal	**FERC Form 1, Page 402**	8,517	8,517	8,517	8,517	8,517
Average Cost of Fuel - Coal - per unit burned	**FERC Form 1, Page 402**	$ 19.59	$ 20.80	$ 21.53	$ 22.86	$ 24.11
Average BTU / kWh (Heat Rate)	**FERC Form 1, Page 402**	10,198	10,060	10,125	10,081	10,116
Net Generation		3,539,923,433	3,561,096,546	2,414,448,790	4,354,707,207	4,354,707,207
Coal Cost (Total)		**41,517,067**	**43,745,000**	**30,898,715**	**58,914,495**	**62,346,284**
Quantity Oil	**FERC Form 1, Page 402**	11,960	7,418	8,006	6178	8390.5
Average cost of oil - per unit burned	**FERC Form 1, Page 402**	46.055	$ 57.53	$ 80.27	89.201	97.01
Oil cost Total		**$ 550,818**	**$ 426,758**	**$ 642,642**	**$ 551,084**	**$ 813,962**
Total Fuel Cost		**$ 42,067,885**	**$ 44,171,758**	**$ 31,541,357**	**$ 59,465,579**	**$ 63,160,246**

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Cost Projections -10% Interest in Boardman Coal Plant

Analysis of Coal Fuel Cost

	2009	2010	2011	2012	2013
Oil Price Escalation	3.00%	3.00%	3.00%	3.00%	3.00%
Inflations Rate	2.00%	2.00%	2.00%	2.00%	2.00%
Inflation Factor	106.1%	108.2%	110.4%	112.6%	114.9%
Coal ($2006) - Delivered Price - March 2008 # DOE/EIA-0383	36.19	36.63	36.06	35.24	34.73
Coal Nominal	$ 38.41	$ 39.65	$ 39.81	$ 39.69	$ 39.89
Percentage Change in Coal Price (Nominal)	4.78%	3.24%	0.41%	-0.32%	0.52%
			Forecast - Projection		
	2009	2010	2011	2012	2013
Net Continuous Plant Capability (MW)	585	585	585	585	585
Hours Connected to load					
Capacity Factor	84.98%	84.98%	84.98%	84.98%	84.98%
Fuel					
Fuel Burned					
Quantity Coal (tons)	2,586,135	2,586,135	2,586,135	2,586,135	2,586,135
Average Heat Content - Coal	8,517	8,517	8,517	8,517	8,517
Average Cost of Fuel - Coal - per unit burned	$ 25.26	$ 26.08	$ 26.19	$ 26.10	$ 26.24
Average BTU / kWh (Heat Rate)	10,116	10,116	10,116	10,116	10,116
Net Generation	4,354,707,207	4,354,707,207	4,354,707,207	4,354,707,207	4,354,707,207
Coal Cost (Total)	**65,326,093**	**67,442,738**	**67,721,126**	**67,504,779**	**67,858,393**
Average Annual Percentage Increase	4.78%	3.24%	0.41%	-0.32%	0.52%
Average Percentage Increase FY 2010-2013		**0.96%**			
Quantity Oil	8390.5	8390.5	8390.5	8390.5	8390.5
Average cost - Oil - per unit burned	99.92	102.92	106.01	109.19	112.46
Oil cost Total	**$ 838,381**	**$ 863,532**	**$ 889,438**	**$ 916,121**	**$ 943,605**
Total Fuel Cost	**$ 66,164,474**	**$ 68,306,270**	**$ 68,610,564**	**$ 68,420,900**	**$ 68,801,998**

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WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant
Summary of Annual Debt Service Amounts - 10% Interest

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Annual Debt Service Increments:						
Original Plant Investment	3,381,700	3,381,700	3,381,700	3,381,700	3,381,700	3,381,700
FY 2005 and Prior Additions	213,871	213,871	213,871	213,871	213,871	213,871
FY 2007 Additions	55,437	55,437	55,437	55,437	55,437	55,437
FY 2008 Additions	19,910	19,910	19,910	19,910	19,910	19,910
FY 2009 Additions	90,178	90,178	90,178	90,178	90,178	90,178
FY 2010 Additions	74,730	74,730	74,730	74,730	74,730	74,730
FY 2011 Additions	0	357,968	357,968	357,968	357,968	357,968
FY 2012 Additions	0	0	77,789	77,789	77,789	77,789
FY 2013 Additions	0	0	0	79,357	79,357	79,357
FY 2014 Additions	0	0	0	0	3,214,580	3,214,580
FY 2015 Additions	0	0	0	0	0	82,650
Total Annual Debt Service Amounts	3,835,826	4,193,795	4,271,583	4,350,940	7,565,520	7,648,171

Projected Annual Capital Additions

	Annual Additions	**Cumulative Cost - 100%**
1980 Additions	591,000,000	591,000,000
1981-2004 Additions	13,085,247	604,085,247
2005 Additions	18,145,870	622,231,117
2006 Retirements	(359,817)	621,871,300
2007 Additions - FERC Form No. 1 for 2007, page 402	7,037,182	628,908,482
Total Asset Cost -line 17, FERC Form No. 1 - FY 2007		628,908,482
PGE 2008 Final Budget - Capital Additions	8,803,660	
Projected Total Asset Cost - FY 2008		637,712,142
PGE 2009 Preliminary Capital Budget Projections	11,364,709	649,076,851
BPA Projected 2010 Capital Additions	9,431,743	658,508,594
PGE BART Pollution Control Additions - 2011	35,574,407	694,083,001
BPA Projected 2011 Other Capital Additions	9,622,566	703,705,567
PGE BART Pollution Control Additions - 2012	0	703,705,567
BPA Projected 2012 Other Capital Additions	9,823,934	713,529,501
PGE BART Pollution Control Additions - 2013	0	713,529,501
BPA Projected 2013 Other Capital Additions	10,023,943	723,553,444
PGE BART Pollution Control Additions - 2014	395,615,477	1,119,168,921
BPA Projected 2014 Other Capital Additions	10,226,962	1,129,395,883
PGE BART Pollution Control Additions - 2015	0	1,129,395,883
BPA Projected Capital Additions - 2015	10,432,394	1,139,828,277
Projected Total Asset Cost - 12/31/2015		1,139,828,277

Note: PGE's FERC Form 1 Indicates that the original plant is being depreciated over 60 years.
Note: PGE's BART Pollution control report indicates that the average useful life of pollution control equipment is 20 years.
Note: BPA assumes that the average useful life of other asset additions during 2008-2015 is 20 years.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

				Initial Investment Amount		
				Total AMT	PRC AMT	
Total Capitalized Cost - 1980				591,000,000	59,100,000	Payment
Debt/Capital Mix				80 /20	100 / 0	Amounts
Amount financed in 1980				472,800,000	59,100,000	
30 year Bond @10% in 1980			59,100,000	10.00%	10.00%	6,269,284
Refinance in 1990 - 30 yr. @ 8%			53,373,938	8.00%	8.00%	4,741,071
Refinance in 2000 - 30 yr. @ 6%			46,548,508	6.00%	6.00%	3,381,700
			Payment Amount	Interest	Principle	Balance
Beginning Balance						59,100,000
	1	1980	6,269,284	5,910,000	359,284	58,740,716
	2	1981	6,269,284	5,874,072	395,212	58,345,504
	3	1982	6,269,284	5,834,550	434,734	57,910,770
	4	1983	6,269,284	5,791,077	478,207	57,432,563
	5	1984	6,269,284	5,743,256	526,028	56,906,535
	6	1985	6,269,284	5,690,654	578,630	56,327,905
	7	1986	6,269,284	5,632,790	636,494	55,691,411
	8	1987	6,269,284	5,569,141	700,143	54,991,268
	9	1988	6,269,284	5,499,127	770,157	54,221,111
	10	1989	6,269,284	5,422,111	847,173	53,373,938
	11	1990	4,741,071	4,269,915	471,156	52,902,782
	12	1991	4,741,071	4,232,223	508,848	52,393,934
	13	1992	4,741,071	4,191,515	549,556	51,844,378
	14	1993	4,741,071	4,147,550	593,521	51,250,857
	15	1994	4,741,071	4,100,069	641,002	50,609,854
	16	1995	4,741,071	4,048,788	692,283	49,917,572
	17	1996	4,741,071	3,993,406	747,665	49,169,907
	18	1997	4,741,071	3,933,593	807,478	48,362,428
	19	1998	4,741,071	3,868,994	872,077	47,490,351
	20	1999	4,741,071	3,799,228	941,843	46,548,508
	21	2000	3,381,700	2,792,911	588,789	45,959,719
	22	2001	3,381,700	2,757,583	624,117	45,335,602
	23	2002	3,381,700	2,720,136	661,564	44,674,038
	24	2003	3,381,700	2,680,442	701,258	43,972,781
	25	2004	3,381,700	2,638,367	743,333	43,229,447
	26	2005	3,381,700	2,593,767	787,933	42,441,514
	27	2006	3,381,700	2,546,491	835,209	41,606,305
	28	2007	3,381,700	2,496,378	885,322	40,720,983
	29	2008	3,381,700	2,443,259	938,441	39,782,542
	30	2009	3,381,700	2,386,953	994,747	38,787,795
	31	2010	3,381,700	2,327,268	1,054,432	37,733,363
	32	2011	3,381,700	2,264,002	1,117,698	36,615,664
	33	2012	3,381,700	2,196,940	1,184,760	35,430,904
	34	2013	3,381,700	2,125,854	1,255,846	34,175,059
	35	2014	3,381,700	2,050,504	1,331,196	32,843,862
	36	2015	3,381,700	1,970,632	1,411,068	31,432,794

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2005 and Prior Capital Additions after Initial Investment</u>

Debt Financing for 1982-2005 Capital Additions $31,231,117

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 1981-2006	31,231,117	3,123,112
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2005 (10/01/2004)	24,984,894	3,123,112
Financing Costs	493,960	12,888
Total Financing	25,478,854	3,136,000
30 year Bond @ 5.42% in 2005 - 1/	6.79%	5.42%
Payment amount - annual		$213,870.87

Note 1 - Interest rate from PFM financing study dated July 2006 Table I, page A-18

			Payment Amount	Interest	Principle	Balance
Beginning Balance						3,136,000
	1	2005	213,871	169,971	43,900	3,092,100
	2	2006	213,871	167,592	46,279	3,045,821
	3	2007	213,871	165,083	48,787	2,997,034
	4	2008	213,871	162,439	51,432	2,945,602
	5	2009	213,871	159,652	54,219	2,891,383
	6	2010	213,871	156,713	57,158	2,834,225
	7	2011	213,871	153,615	60,256	2,773,969
	8	2012	213,871	150,349	63,522	2,710,447
	9	2013	213,871	146,906	66,965	2,643,482
	10	2014	213,871	143,277	70,594	2,572,888
	11	2015	213,871	139,451	74,420	2,498,468
	12	2016	213,871	135,417	78,454	2,420,014
	13	2017	213,871	131,165	82,706	2,337,308
	14	2018	213,871	126,682	87,189	2,250,119
	15	2019	213,871	121,956	91,914	2,158,205
	16	2020	213,871	116,975	96,896	2,061,309
	17	2021	213,871	111,723	102,148	1,959,161
	18	2022	213,871	106,187	107,684	1,851,476
	19	2023	213,871	100,350	113,521	1,737,956
	20	2024	213,871	94,197	119,674	1,618,282
	21	2025	213,871	87,711	126,160	1,492,122
	22	2026	213,871	80,873	132,998	1,359,124
	23	2027	213,871	73,665	140,206	1,218,918
	24	2028	213,871	66,065	147,806	1,071,112
	25	2029	213,871	58,054	155,817	915,296
	26	2030	213,871	49,609	164,262	751,034
	27	2031	213,871	40,706	173,165	577,869
	28	2032	213,871	31,320	182,550	395,318

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2007 Capital Additions

2007 Capital Additions $7,037,182

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2007	7,037,182	703,718
2007 Additions - Agrees to FERC Form No. 1 for 2007, page 402		
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in 2007 10-01-2006	5,629,746	703,718
Financing Costs	20,254	6,282
Total Financing	5,650,000	710,000
20 year Bond @ 4.68% in 2007 - 1/	4.73%	4.68%
Payment amount - annual		55,436.70

Note 1 - Interest rate from PFM financing study dated 08/21/08, Table D, page 15

			Payment Amount	Interest	Principle	Balance
Beginning Balance						710,000
	1	2007	55,437	33,228	22,209	687,792
	2	2008	55,437	32,189	23,248	664,543
	3	2009	55,437	31,101	24,336	640,207
	4	2010	55,437	29,962	25,475	614,732
	5	2011	55,437	28,769	26,667	588,065
	6	2012	55,437	27,521	27,915	560,150
	7	2013	55,437	26,215	29,222	530,928
	8	2014	55,437	24,847	30,589	500,339
	9	2015	55,437	23,416	32,021	468,318
	10	2016	55,437	21,917	33,519	434,799
	11	2017	55,437	20,349	35,088	399,711
	12	2018	55,437	18,706	36,730	362,980
	13	2019	55,437	16,987	38,449	324,531
	14	2020	55,437	15,188	40,249	284,283
	15	2021	55,437	13,304	42,132	242,150
	16	2022	55,437	11,333	44,104	198,046
	17	2023	55,437	9,269	46,168	151,878
	18	2024	55,437	7,108	48,329	103,549
	19	2025	55,437	4,846	50,591	52,959
	20	2026	55,426	2,478	52,947	11

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2008 Capital Additions

PGE 2008 Final Capital Budget	$8,803,660		
2008 Capital Additions	$8,803,660		
		Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2008		8,803,660	880,366
Debt/Capital Mix		80 /20	100 / 0
Capital Costs financed in 2008 (10-01-2007)		7,042,928	880,366
Financing Costs		70,309	9,634
Total Financing		7,113,237	890,000
20 year Bond @ 4.68% in 2008 - 1/		4.73%	4.68%
Payment amount - annual			69,491

Note 1 - Interest rate from PFM financing study dated 08/21/08, Table D, page 15

		Year	Payment Amount	Interest	Principle	Balance
Beginning Balance - 10/01/2007						890,000
	1	2008	69,491	41,652	27,839	862,161
	2	2009	69,491	40,349	29,142	833,019
	3	2010	69,491	38,985	30,506	802,513
	4	2011	69,491	37,558	31,933	770,579
	5	2012	69,491	36,063	33,428	737,152
	6	2013	69,491	34,499	34,992	702,159
	7	2014	69,491	32,861	36,630	665,529
	8	2015	69,491	31,147	38,344	627,185
	9	2016	69,491	29,352	40,139	587,046
	10	2017	69,491	27,474	42,017	545,029
	11	2018	69,491	25,507	43,984	501,045
	12	2019	69,491	23,449	46,042	455,003
	13	2020	69,491	21,294	48,197	406,806
	14	2021	69,491	19,039	50,453	356,354
	15	2022	69,491	16,677	52,814	303,540
	16	2023	69,491	14,206	55,285	248,255
	17	2024	69,491	11,618	57,873	190,382
	18	2025	69,491	8,910	60,581	129,801
	19	2026	69,491	6,075	63,416	66,384
	20	2027	69,493	3,107	66,386	(2)

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2009 Capital Additions</u>

PGE 2009 Preliminary Capital Budget $11,364,709

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2009	11,364,709	1,136,471
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2009 (10-01-2008)	9,091,767	1,136,471
Financing Costs	90,798	13,529
Total Financing	9,182,565	1,150,000
20 year Bond @ 4.73% in 2009 - 1/	N/A	4.73%
Payment amount - annual		90,178.24

<u>Note 1</u> - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

		Year	Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2008						1,150,000
	1	2009	90,178	54,395	35,783	1,114,216
	2	2010	90,178	52,702	37,476	1,076,741
	3	2011	90,178	50,930	39,248	1,037,492
	4	2012	90,178	49,073	41,105	996,387
	5	2013	90,178	47,129	43,049	953,338
	6	2014	90,178	45,093	45,085	908,253
	7	2015	90,178	42,960	47,218	861,035
	8	2016	90,178	40,727	49,451	811,584
	9	2017	90,178	38,388	51,790	759,793
	10	2018	90,178	35,938	54,240	705,553
	11	2019	90,178	33,373	56,806	648,748
	12	2020	90,178	30,686	59,492	589,255
	13	2021	90,178	27,872	62,306	526,949
	14	2022	90,178	24,925	65,254	461,695
	15	2023	90,178	21,838	68,340	393,355
	16	2024	90,178	18,606	71,573	321,783
	17	2025	90,178	15,220	74,958	246,825
	18	2026	90,178	11,675	78,503	168,321
	19	2027	90,178	7,962	82,217	86,105
	20	2028	90,184	4,073	86,111	(7)

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2010 Capital Additions

BPA Projected 2010 Capital Additions - 2/ $9,431,743
(Average of 2007, 2008 and 2009 Capital additions)

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2010	9,431,743	943,174
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2009 (10-01-2009)	7,545,394	943,174
Financing Costs	75,334	9,826
Total Financing	7,620,728	953,000
20 year Bond @ 4.73% in 2009 - 1/	N/A	4.73%
Payment amount - annual		74,730

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2009						953,000
	1	2010	74,730	45,077	29,653	923,347
	2	2011	74,730	43,674	31,056	892,291
	3	2012	74,730	42,205	32,525	859,766
	4	2013	74,730	40,667	34,063	825,702
	5	2014	74,730	39,056	35,675	790,028
	6	2015	74,730	37,368	37,362	752,666
	7	2016	74,730	35,601	39,129	713,536
	8	2017	74,730	33,750	40,980	672,556
	9	2018	74,730	31,812	42,918	629,638
	10	2019	74,730	29,782	44,948	584,689
	11	2020	74,730	27,656	47,075	537,615
	12	2021	74,730	25,429	49,301	488,314
	13	2022	74,730	23,097	51,633	436,681
	14	2023	74,730	20,655	54,075	382,605
	15	2024	74,730	18,097	56,633	325,972
	16	2025	74,730	15,418	59,312	266,660
	17	2026	74,730	12,613	62,117	204,543
	18	2027	74,730	9,675	65,055	139,488
	19	2028	74,730	6,598	68,133	71,355
	20	2029	74,736	3,375	71,361	(6)

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2011 Capital Additions

BPA Projected Other 2011 Capital Additions - 2/	$9,622,566
PGE BART Pollution Control Additions - 2011	$35,574,407
Total Capital Additions	$45,196,973

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2011	45,196,973	4,519,697
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2011 (10-01-2010)	36,157,578	4,519,697
Financing Costs	361,455	45,303
Total Financing	36,519,033	4,565,000
20 year Bond @ 4.73% in 2011 - 1/	N/A	4.73%
Payment amount - annual		357,968

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2010						4,565,000
	1	2011	357,968	215,925	142,044	4,422,956
	2	2012	357,968	209,206	148,763	4,274,194
	3	2013	357,968	202,169	155,799	4,118,395
	4	2014	357,968	194,800	163,168	3,955,226
	5	2015	357,968	187,082	170,886	3,784,340
	6	2016	357,968	178,999	178,969	3,605,371
	7	2017	357,968	170,534	187,434	3,417,937
	8	2018	357,968	161,668	196,300	3,221,636
	9	2019	357,968	152,383	205,585	3,016,051
	10	2020	357,968	142,659	215,309	2,800,742
	11	2021	357,968	132,475	225,493	2,575,249
	12	2022	357,968	121,809	236,159	2,339,090
	13	2023	357,968	110,639	247,329	2,091,760
	14	2024	357,968	98,940	259,028	1,832,732
	15	2025	357,968	86,688	271,280	1,561,452
	16	2026	357,968	73,857	284,112	1,277,340
	17	2027	357,968	60,418	297,550	979,790
	18	2028	357,968	46,344	311,624	668,165
	19	2029	357,968	31,604	326,364	341,801
	20	2030	357,983	16,167	341,816	(15)

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.020232 for 2011$$ this amount is $9,622,566.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2012 Capital Additions</u>

BPA Projected Other 2012 Capital Additions - 2/	$9,823,934
PGE BART Pollution Control Additions - 2012	0
Total Capital Additions	$9,823,934

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2012	9,823,934	982,393
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2012 (10-01-2011)	7,859,147	982,393
Financing Costs	78,259	9,607
Total Financing	7,937,407	992,000
20 year Bond @ 4.73% in 2012 - 1/	N/A	4.73%
Payment amount - annual		77,789

<u>Note 1</u> - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2011						992,000
	1	2012	77,789	46,922	30,867	961,133
	2	2013	77,789	45,462	32,327	928,806
	3	2014	77,789	43,933	33,856	894,950
	4	2015	77,789	42,331	35,457	859,493
	5	2016	77,789	40,654	37,135	822,358
	6	2017	77,789	38,898	38,891	783,467
	7	2018	77,789	37,058	40,731	742,737
	8	2019	77,789	35,131	42,657	700,080
	9	2020	77,789	33,114	44,675	655,405
	10	2021	77,789	31,001	46,788	608,617
	11	2022	77,789	28,788	49,001	559,616
	12	2023	77,789	26,470	51,319	508,297
	13	2024	77,789	24,042	53,746	454,551
	14	2025	77,789	21,500	56,288	398,263
	15	2026	77,789	18,838	58,951	339,312
	16	2027	77,789	16,049	61,739	277,573
	17	2028	77,789	13,129	64,659	212,914
	18	2029	77,789	10,071	67,718	145,196
	19	2030	77,789	6,868	70,921	74,275
	20	2031	77,775	3,513	74,261	14

<u>Note 2</u> - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.041582 for 2012$$ this amount is $9,823,934.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2013 Capital Additions</u>

BPA Projected Other 2013 Capital Additions - 2/	$10,023,943
PGE BART Pollution Control Additions - 2013	0
Total Capital Additions	$10,023,943

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2013	10,023,943	1,002,394
Debt/Capital Mix	80 /20	100 / 0
Cap. Costs financed in FY 2013 (10-01-2012)	8,019,154	1,002,394
Financing Costs	80,324	9,606
Total Financing	8,099,478	1,012,000
20 year Bond @ 4.73% in 2013 - 1/	N/A	4.73%
Payment amount - annual		79,357

<u>Note 1</u> - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2012						1,012,000
	1	2013	79,357	47,868	31,489	980,511
	2	2014	79,357	46,378	32,979	947,532
	3	2015	79,357	44,818	34,539	912,994
	4	2016	79,357	43,185	36,172	876,821
	5	2017	79,357	41,474	37,883	838,938
	6	2018	79,357	39,682	39,675	799,263
	7	2019	79,357	37,805	41,552	757,711
	8	2020	79,357	35,840	43,517	714,194
	9	2021	79,357	33,781	45,575	668,619
	10	2022	79,357	31,626	47,731	620,888
	11	2023	79,357	29,368	49,989	570,899
	12	2024	79,357	27,004	52,353	518,545
	13	2025	79,357	24,527	54,830	463,716
	14	2026	79,357	21,934	57,423	406,292
	15	2027	79,357	19,218	60,139	346,153
	16	2028	79,357	16,373	62,984	283,169
	17	2029	79,357	13,394	65,963	217,206
	18	2030	79,357	10,274	69,083	148,123
	19	2031	79,357	7,006	72,351	75,773
	20	2032	79,355	3,584	75,771	2

<u>Note 2</u> - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.062788 for 2013$$ this amount is $10,023,943.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack

Debt Service Projections - 10% Interest in Boardman Coal Plant

<u>FY 2014 Capital Additions</u>

BPA Projected Other 2014 Capital Additions - 2/	$10,226,962
PGE BART Pollution Control Additions - 2014	395,615,477
Total Capital Additions	$405,842,439

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2014	405,842,439	40,584,244
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2014 (10-01-2013)	324,673,951	40,584,244
Financing Costs	3,246,488	405,540
Total Financing	327,920,439	40,994,000
20 year Bond @ 4.73% in 2014 - 1/	N/A	4.73%
Payment amount - annual		3,214,580

<u>Note 1</u> - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2012						40,994,000
	1	2014	3,214,580	1,939,016	1,275,564	39,718,437
	2	2015	3,214,580	1,878,682	1,335,898	38,382,539
	3	2016	3,214,580	1,815,494	1,399,086	36,983,453
	4	2017	3,214,580	1,749,317	1,465,263	35,518,190
	5	2018	3,214,580	1,680,010	1,534,570	33,983,621
	6	2019	3,214,580	1,607,425	1,607,155	32,376,466
	7	2020	3,214,580	1,531,407	1,683,173	30,693,293
	8	2021	3,214,580	1,451,793	1,762,787	28,930,506
	9	2022	3,214,580	1,368,413	1,846,167	27,084,339
	10	2023	3,214,580	1,281,089	1,933,491	25,150,848
	11	2024	3,214,580	1,189,635	2,024,945	23,125,903
	12	2025	3,214,580	1,093,855	2,120,725	21,005,178
	13	2026	3,214,580	993,545	2,221,035	18,784,143
	14	2027	3,214,580	888,490	2,326,090	16,458,054
	15	2028	3,214,580	778,466	2,436,114	14,021,940
	16	2029	3,214,580	663,238	2,551,342	11,470,597
	17	2030	3,214,580	542,559	2,672,021	8,798,577
	18	2031	3,214,580	416,173	2,798,407	6,000,169
	19	2032	3,214,580	283,808	2,930,772	3,069,397
	20	2033	3,214,577	145,182	3,069,394	3

<u>Note 2</u> - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.084313 for 2014$$ this amount is $10,226,962.

WP-10 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack
Debt Service Projections - 10% Interest in Boardman Coal Plant

FY 2015 Capital Additions

BPA Projected Other 2015 Capital Additions - 2/	$10,432,394
PGE BART Pollution Control Additions - 2015	0
Total Capital Additions	$10,432,394

	Total AMT	PRC AMT
Total Capitalized / Financed Costs - 2015	10,432,394	1,043,239
Debt/Capital Mix	80 /20	100 / 0
Capital Costs financed in FY 2014 (10-01-2013)	8,345,915	1,043,239
Financing Costs	83,459	10,761
Total Financing	8,429,374	1,054,001
20 year Bond @ 4.73% in 2014 - 1/	N/A	4.73%
Payment amount - annual		82,650

Note 1 - Interest rate from PFM Financing Study dated 11/11/08, See Appendix A, Table D, page 14.

			Payment Amount	4.73% Interest	Principle	Balance
Beginning Balance - 10/01/2012						1,054,001
	1	2015	82,650	49,854	32,796	1,021,205
	2	2016	82,650	48,303	34,347	986,857
	3	2017	82,650	46,678	35,972	950,885
	4	2018	82,650	44,977	37,674	913,212
	5	2019	82,650	43,195	39,455	873,756
	6	2020	82,650	41,329	41,322	832,435
	7	2021	82,650	39,374	43,276	789,158
	8	2022	82,650	37,327	45,323	743,835
	9	2023	82,650	35,183	47,467	696,368
	10	2024	82,650	32,938	49,712	646,656
	11	2025	82,650	30,587	52,064	594,592
	12	2026	82,650	28,124	54,526	540,066
	13	2027	82,650	25,545	57,105	482,961
	14	2028	82,650	22,844	59,806	423,155
	15	2029	82,650	20,015	62,635	360,519
	16	2030	82,650	17,053	65,598	294,922
	17	2031	82,650	13,950	68,701	226,221
	18	2032	82,650	10,700	71,950	154,271
	19	2033	82,650	7,297	75,353	78,918
	20	2034	82,656	3,733	78,924	(6)

Note 2 - PGE's Boardman capital budgets are estimated at $7,037,182 for 2007; $8,803,660 for 2008; and $11,364,709 for 2009. The simple average for the 3-years is $9,068,517, restated in 2010$$ this average amount is $9,431,743, escalated at 1.106094 for 2015$$ this amount is $10,432,394.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Boardman (b)			Plant Name: Boardman (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1980			1980
4	Year Last Unit was Installed			1980			1980
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			642.20			417.43
6	Net Peak Demand on Plant - MW (60 minutes)			595			0
7	Plant Hours Connected to Load			6686			0
8	Net Continuous Plant Capability (Megawatts)			0			0
9	When Not Limited by Condenser Water			585			0
10	When Limited by Condenser Water			585			0
11	Average Number of Employees			110			0
12	Net Generation, Exclusive of Plant Use - KWh			4354531000			2827461000
13	Cost of Plant: Land and Land Rights			1240068			798844
14	Structures and Improvements			151883454			99959737
15	Equipment Costs			474946319			304980403
16	Asset Retirement Costs			838641			622117
17	Total Cost			628908482			406361101
18	Cost per KW of Installed Capacity (line 17/5) Including			979.3031			973.4832
19	Production Expenses: Oper, Supv, & Engr			6763843			4420104
20	Fuel			61041164			39933425
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			0			0
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			0			0
26	Misc Steam (or Nuclear) Power Expenses			2169128			1387631
27	Rents			0			0
28	Allowances			0			0
29	Maintenance Supervision and Engineering			19406261			12370455
30	Maintenance of Structures			0			0
31	Maintenance of Boiler (or reactor) Plant			0			0
32	Maintenance of Electric Plant			0			0
33	Maintenance of Misc Steam (or Nuclear) Plant			163697			106530
34	Total Production Expenses			89544093			58218145
35	Expenses per Net KWh			0.0206			0.0206
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil	Composite			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	2577187	6178	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8517	138600	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	23.264	93.920	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	22.858	89.201	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.342	15.324	1.353	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.014	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10081.400	8.300	10089.700	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see unt 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Clackamas River Hydro Relicensing Project	50,223,922
2	Pelton/R. Butte-Selective Water Withdrawal	28,140,038
3	Biglow Canyon Wind Farm Generation Project (Phases 2 & 3)	17,828,002
4	Carver Sub-Install VWR-4 Transformer	3,422,545
5	Energy Management System-Software	2,639,743
6	Sullivan Fish Passage	2,088,749
7	River District-Install Vaults	1,577,886
8	Pelton/Round Butte Hydro Facility - FERC License Requirements	1,552,732
9	Purchase Spare Bulk Transformers	1,419,662
10	Advanced Metering Infrastructure	1,183,873
11	Develop Automated Meter Exchange System - Software	1,175,189
12	Install Microsoft Exchange and Windows Technology-Software	1,076,112
13	Boardman Plant-Install Training Simulator	988,836
14	Carver Sub-Install 230-Kv Line Position	898,772
15	Identity Management Control System - Software	833,267
16	Boardman Plant-Rewind Generator Stator	792,607
17	Fiber Optic Cable Project-Portland's Eastside	773,188
18	McLoughlin Sub-Install 230-Kv Line Position	680,540
19	Web Infrastructure-Software	653,320
20	River Mill-Fish Passage Improvement	537,690
21	Boardman Plant-Purchase Spare Generator	467,226
22	Colstrip Plant-Capital Yearend Accrual	441,750
23	Beaver Plant-Install Remedial Action Scheme	339,673
24	Construct Carver-McLoughlin 230-Kv Line	330,768
25	Kelly Butte Sub-Install SCADA System	296,930
26	Sunset Sub-Install ZVC Switches	291,640
27	Beaver Plant-Rewind Generator Rotor Unit	258,902
28	River Mill Plant-Construct Boat Launch	256,788
29	Carver Sub-Install Carver-Hogan South 115-Kv Line	230,193
30	West Side Hydros-Install Safety (SHARPS) Upgrades	222,129
31	Carver Sub-Install Carver-Canemah 115-Kv Line	207,999
32	Progress Sub-Install SCADA System	203,522
33	Colstrip Plant-Install Mercury Controls for Units 3 & 4	194,677
34	Bald Peak Communication Station-Replace Alarm Monitoring on Communications Systems	192,831
35	Coffee Creek Sub-Build New Substation	188,668
36	Boardman Plant-Install Superheat Safety Valve	155,308
37	Purchase Helicopter	152,666
38	Coyote Springs Plant-Add Auto Bus Transfer to 115-Kv Line	139,057
39	McGill Sub-Replace WR-1 Transformer	131,131
40	R. Butte Switchyard-Replace 500-Kv Transformer Reactor Switches	128,360
41	Coyote Springs Plant-Automate Heat-Recovery-Steam-Generator (HRSG) Valves	122,696
	Boardman Plant-Extend Dike and Piping at Carty Reservoir	112,260
43	TOTAL	125,676,924

Bonneville Power Administration
2007 Supplemental Wholesale Power Rate Case Initial Proposal

WP-07-E-BPA-88
(BPA-JP6-23)

PGE 2007 Supplemental Wholesale Power Rate Case Data Response

DATA REQUEST NUMBER: BPA-JP6-23

REQUEST DATE: May 15, 2008
REPSONSE DATE: May 22, 2008
DIRECTED TO: PGE

REQUESTOR'S NAME: Paul A. Brodie
AGENCY: BPA

EXHIBIT: WP-07-E-JP6-12

PAGE(S): 37-38

DATA REQUEST:

The above-cited rebuttal testimony addresses the projected costs used in the current rate proceeding. Please provide a copy of annual historical operating budgets for the operation of the Boardman coal plant for the years 2002-2008. Also, please provide the projected operating budgets for the Boardman coal plant to the extent available for CYs 2009-2013.

Paul A Brodie, CPA
Bonneville Power Rate Staff
503-230-3414

PGE RESPONSE:

See BPA-JP6-23 Attachments A and B for the requested information. Attachment A provides the PGE share of annual historical operating costs for the Boardman coal plant for the years 2002-2007. A copy of the 2008 Boardman Operations budget is provided as Attachment B; the PGE share would be 65% of these totals.

PGE does not have future year projected amounts to be charged to the other owners available. The Operation agreement requires only that a budget be prepared for the next year's activity. Funding of cost activities for the Boardman plant is done weekly with the other owners. Each company is responsible for having funds available as required, including those for capital construction, decommissioning, or any other activities necessary for continued operation.

BPA-JP-23 Attachment A

Portland General Electric
Response to Data Request: BPA-JP-23
5/21/2008

2002-2007 Operating Costs for PGE's Share of the Boardman Coal Plant *

Line	Operating Cost	2002	2003	2004	2005	2006	2007
1	Production Expenses: Oper. Supv. & Engr	3,123,338	3,197,010	4,457,560	3,818,762	3,742,813	4,420,104
2	Fuel	34,998,755	37,580,945	29,909,037	31,124,332	22,218,265	39,933,425
3	Misc Steam Power Expenses	1,734,302	1,733,390	789,729	1,432,334	1,341,837	1,387,631
4	Rents	2,662,404	2,726,569	2,688,319	640,712	-	-
5	Allowances	52,879	-	-	-	-	-
6	Maintenance Supervision and Engineering	9,645,388	9,541,455	15,116,268	12,396,430	11,752,427.00	12,370,455
7	Maintenance of Misc Steam Plant	86,914	144,319	119,863	89,610	67,827	106,530
8		52,303,980	54,923,688	53,080,776	49,502,180	39,123,169	58,218,145

* Note: PGE Share From page 402 of PGE FERC Form 1

BPA-JP-23 Attachment B

PORTLAND GENERAL ELECTRIC COMPANY
2008 BOARDMAN COAL PLANT OPERATIONS BUDGET - TOTAL
100% Corporate Loadings Included

	FERC	Final 2008 BUDGET
OPERATIONS		
STEAM POWER GENERATING EXPENSES:		
OPERATIONS SUPV & ENGR	500	7,086,196
FUEL COST	501	1,864,722
MISC STEAM POWER EXPENSES	506	2,093,620
RENTS	507	-
OTHER POWER SUPPLY EXPENSES:		
MISC OTHER POWER SUPPLY EXPENSE	557	172,875
ADMINISTRATIVE AND GENERAL EXPENSES:		
ADMINISTRATIVE & GENERAL	921	2,330,763
PROPERTY INSURANCE/LEGAL	924	580,550
INJURIES AND DAMAGES	925	154,695
EMPLOYEE BENEFITS	926	2,872,206
REGULATORY COMMISSION EXPENSES	928	-
MISC GENERAL EXPENSES	930	15,000
TOTAL OPERATIONS		17,170,627
STEAM POWER MAINTENANCE EXPENSES:		
MAINT SUPV & ENGR	510	18,812,003
MAINT OF MISC PLANT	514	44,738
MAINT OF LOAD DISPATCHING	561	-
MAINT OF STATION EQUIP (TRANSMIS.)	570	45,622
MAINT OVERHEAD LINES (TRANSMIS.)	571	-
MAINT OF MISC TRANSMISSION PLANT	573	-
TOTAL MAINTENANCE		18,902,363
FUEL, TAXES, INTEREST AND OTHER:		
FUEL INVENTORY-COAL PURCHASE	151	62,346,284
FUEL INVENTORY-COAL FIXED O&M	151	1,930,798
FUEL INVENTORY-OIL PURCHASE	151	813,962
PAYROLL TAXES	408	1,016,802
INTEREST EXPENSE	427	
OTHER MISC ELECTRIC REVENUES	456	(600,000)
TOTAL FUEL ,TAXES AND INTEREST		65,507,846

Brodie,Paul A - PFR-6

From:	Valerie Giles [Valerie.Giles@pgn.com]
Sent:	Monday, December 15, 2008 9:28 AM
To:	Brodie,Paul A - PFR-6
Cc:	Forman,Charles W - PSW-6; Bliven,Raymond D - PFR-6; Stefan Brown
Subject:	2009 Boardman Preliminary Budget
Attachments:	2009_PRE_budget.xls

Attached is the 2009 preliminary O&M and Capital budget for Boardman provided to the co-owners in September 2009.

Valerie Giles
Manager, Generation & Asset Accounting
Portland General Electric
(503) 464-7307
(503) 464-2507 Fax
Valerie.Giles@pgn.com

PORTLAND GENERAL ELECTRIC COMPANY
BOARDMAN COAL PLANT OPERATIONS BUDGET COMPARISON - PRELIMINARY
100% Corporate Loadings Included

	FERC	Preliminary 2009 BUDGET	Final 2008 BUDGET	VARIANCE Incr (Decr)
OPERATIONS				
STEAM POWER GENERATING EXPENSES:				
OPERATIONS SUPV & ENGR	500	7,081,771	7,086,196	(4,425)
FUEL COST	501	1,837,111	1,864,722	(27,611)
MISC STEAM POWER EXPENSES	506	1,990,633	2,093,620	(102,987)
RENTS	507		-	-
OTHER POWER SUPPLY EXPENSES:				-
MISC OTHER POWER SUPPLY EXPENSE	557	160,341	172,875	(12,534)
ADMINISTRATIVE AND GENERAL EXPENSES:				-
ADMINISTRATIVE & GENERAL	921	2,304,675	2,330,763	(26,088)
PROPERTY INSURANCE/LEGAL	924	488,183	580,550	(92,367)
INJURIES AND DAMAGES	925	154,896	154,695	201
EMPLOYEE BENEFITS	926	2,863,196	2,872,206	(9,010)
REGULATORY COMMISSION EXPENSES	928		-	-
MISC GENERAL EXPENSES	930		15,000	(15,000)
TOTAL OPERATIONS		16,880,806	17,170,627	(289,821)
STEAM POWER MAINTENANCE EXPENSES:				
MAINT SUPV & ENGR	510	24,297,083	18,812,003	5,485,080
MAINT OF MISC PLANT	514	42,239	44,738	(2,499)
MAINT OF LOAD DISPATCHING	561		-	-
MAINT OF STATION EQUIP (TRANSMIS.)	570	55,724	45,622	10,102
MAINT OVERHEAD LINES (TRANSMIS.)	571		-	-
MAINT OF MISC TRANSMISSION PLANT	573		-	-
TOTAL MAINTENANCE		24,395,046	18,902,363	5,492,683
FUEL, TAXES, INTEREST AND OTHER:				
FUEL INVENTORY-COAL PURCHASE	151	59,460,450	62,346,284	(2,885,834)
FUEL INVENTORY-COAL FIXED O&M	151	1,601,966	1,930,798	(328,832)
FUEL INVENTORY-OIL PURCHASE	151	1,269,066	813,962	455,104
PAYROLL TAXES	408	1,016,802	1,016,802	-
INTEREST EXPENSE	427			-
OTHER MISC ELECTRIC REVENUES	456	(600,000)	(600,000)	-
TOTAL FUEL ,TAXES AND INTEREST		62,748,284	65,507,846	(2,759,562)
SUBTOTAL		104,024,136	101,580,835	2,443,300
CHANGE IN WORKING CAPITAL:				
PLANT MATERIALS AND SUPPLIES	154			-
STORES EXPENSE UNDISTRIBUTED	163	630,217	718,976	(88,759)
PREPAYMENTS	165	24,000	23,086	914
PRELIMINARY SURVEY & INVESTIGATION	183	1,715,000	2,343,723	(628,723)
CLEARING ACCOUNT - MATERIAL O/H DIST	184	(265,848)	(265,848)	-
MISC. DEFERRED DEBITS	186			-
OTHER LONG TERM DEBT	224			-
DISCOUNT ON LONG TERM DEBT	226			-
INJURIES AND DAMAGES PROVISION	228	35,000	36,000	(1,000)
ACCOUNTS PAYABLE	232	(6,194,852)	(6,219,851)	24,999
TOTAL CHANGES IN WORKING CAPITAL		(4,056,483)	(3,363,914)	(692,569)
SUBTOTAL		99,967,653	98,216,921	1,750,731
CONSTRUCTION/RETIREMENTS	107/108	11,364,709	8,803,660	2,561,049
TOTAL FUNDING REQUESTED		111,332,362	107,020,581	4,311,781

note: used 2008 loadings so differences are direct items

1/2/2009

PORLTAND GENERAL ELECTRIC COMPANY
BOARDMAN COAL PLANT
2009 PRELIMINARY CAPITAL BUDGET

100% with Corporate Loadings Included

Job #	Title	100% Plant Preliminary Budget
C9300	Furniture	10,319
CN089	Portable Electrical Instruments	51,594
CN094	Minor Tools & Equipment	41,275
19888	Vintage Computers	10,319
21616	New Coal Dust Suppression System	61,913
22819	Install New Secondary Air Preheater Baskets	104,059
23260	Miscellaneous Pumps, Valves, Motors, etc.	454,912
24069	Install Platforms (2009)	30,956
24226	Generator Rotor	1,602,399
24554	Rewind Generator Stator	6,478,165
24555	Install New Cooling Water Supply Skid	119,530
24559	Generator DCS Connection	332,453
24561	Generator Start-up Testing & Tuning	256,876
25146	Desktop Vintage & Growth	80,497
25350	Install Type K Pneumatic Controllers - 2009	58,198
25421	Backup Communications Upgrade	9,906
25446	Upgrade Coal Car Dumper Drives	41,275
25452	Upgrade AWS Building HVAC Chillers	167,742
25519	Upgrade Coal Yard PLC Control System	1,055,459
25529	Replace Coal Conduit Bends	154,782
X0045	Misc Jobs to be identified	242,079
	TOTAL	11,364,709

Prepared by: Cathy Geiger
As of 8/29/07 - preliminary budget numbers

PGE

December 17, 2008
ES-266-2008
Gov Rel 9

Mr. Brian Finneran
Oregon Department of Environmental Quality
811 SW Sixth Ave
Portland, OR 97204

Re: Preliminary Comments on Proposed Regional Haze Rules

Dear Brian:

Portland General Electric Company (PGE) appreciates this opportunity to comment on the proposed Regional Haze rulemaking. As you know, the proposed rules are the result of the federal requirement that Oregon submit an initial implementation plan for regional haze (the Regional Haze SIP). This plan must include a determination of Best Available Retrofit Technology (BART) for each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Class I area. 40 CFR § 51.308(e)(1)(ii). The federal Clean Air Act contains specific criteria for establishing BART and these criteria are carried over into the regulations. In developing these regulations, EPA also promulgated guidelines to be used by the states in developing BART determinations. These guidelines, found in 40 CFR § 51 Appendix Y, contain the majority of the detail regarding how BART determinations are to be conducted.

1. Background

On November 2, 2007, PGE submitted a BART analysis for its coal-fired power plant located in Boardman, Oregon (the Boardman plant).[1] Sources in existence on August 7, 1977 and that both fall into one of the designated source categories and have the potential to emit more that 250 tons per year of a haze-causing pollutant are required to determine BART if they cause or contribute to visibility impairment in a mandatory Class I area. 40 CFR § 51.308(e). DEQ previously determined that the Boardman power plant was in existence, as that term is defined in the federal

[1] The Foster-Wheeler boiler is identified by the U.S. Environmental Protection Agency (EPA) as acid rain program ORISPL code 6106.

Regional Haze program, on August 7, 1977.[2] The Boardman plant emits more than 250 tons per year of NOx, SO_2 and PM, is in one of the designated source categories and was determined by the Oregon Department of Environmental Quality (DEQ or Department) to cause visibility impairment in at least one mandatory Class I area. Therefore, PGE engaged an extensive group of experts that assisted the company in preparing a BART determination for the Boardman plant. This report was submitted on November 2, 2007 and subsequently supplemented in response to dozens of questions posed by various state and federal agencies and interested third parties. The team of experts concluded that for the Boardman plant BART constituted the installation of new low-NOx burners with a modified overfire air system for NOx control and the installation of a semi-dry scrubbing system with fabric filters for SO_2 and PM control. PGE concluded that due to the long lead time and complex engineering challenges the company needed five years from the date that the Regional Haze SIP is approved in order to engineer, bid, procure, install and start up the semi-dry scrubbing system. Federal law authorizes DEQ to allow up to five years from the date EPA approves the Regional Haze SIP. 40 CFR § 51.308(e)(1)(iv).

On December 1, 2008, the Department issued the proposed Regional Haze proposal for public comment. The proposal includes new regulations that would require the installation of the controls identified below.

Limit (Assumed Control)	**Installation Deadline**	**Authority**
0.23 lb NOx/MMBtu (Low-NOx Burners/Overfire Air)*	7/1/2011	BART
0.12 lb SO_2/MMBtu 0.012 lb PM/MMBtu (Semi-Dry Scrubber)	7/1/2014	BART
0.070 lb NOx/MMBtu (SCR)	7/1/2017	Reasonable Progress

* If LNB/OFA doesn't meet limit, SNCR required by 7/1/2014

[2] 40 CFR § 51.301 defines "in existence on August 7, 1977" as "meaning that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time."

The Department's proposed BART determination is consistent with the controls determined to be BART by PGE's experts. However, the schedule proposed for installation of the semi-dry scrubber system is shorter than that proposed by PGE. DEQ anticipates presenting the final BART determination package to the Environmental Quality Commission (EQC) at its April 2009 meeting. Assuming the EQC adopts the package in April 2009, it must then be submitted to EPA for approval into the State Implementation Plan (SIP). This process is anticipated to take a minimum of six months and more likely a year or longer. Assuming that EPA does not approve the Regional Haze SIP until July 1, 2010, the proposed rule does not provide all of the time allowed for PGE to install the semi-dry scrubbers.

Although all that is required of DEQ at this time is to promulgate BART, DEQ chose to go further and also impose a requirement under the future "Reasonable Progress" program. The first stage of the Regional Haze program is to determine and require BART. However, each state must subsequently develop a plan to ensure that by 2064 visibility is restored to pre-human levels in mandatory Class I areas (BART and Reasonable Progress controls are evaluated based on benefits to mandatory Class I areas only). Consistent with this requirement, states must submit SIPs containing emissions limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the 2064 visibility goal. DEQ must also demonstrate to EPA every ten years that the state is making reasonable progress towards the ultimate visibility improvement goal. These "Reasonable Progress" demonstrations do not require any determination of controls on stationary sources at this time and we are aware of no western state making Reasonable Progress based control determinations at the same time that the state is making BART determinations. For example, California just released its draft Regional Haze SIP and it is proposing no stationary source Reasonable Progress control determinations. Nonetheless, the Department has proposed as part of this rulemaking that the Boardman plant be required to install additional NOx controls, specifically selective catalytic reduction (SCR), in 2017. These controls were demonstrated not to constitute BART due to their extreme cost and their limited effectiveness in addressing visibility impacts.

PGE has reviewed the Department's proposed BART and Reasonable Progress rules in light of this regulatory and statutory background. Based on our review, we have the following comments.

2. Comments on Proposed NOx BART Rule

NOx BART Limit Determination

PGE supports the Department's NOx BART determination. The proposed NOx BART determination will reduce NOx from the Boardman plant by approximately 46% from current levels by preventing the formation of NOx in the first place. While this comes at a significant capital expense, we believe that these controls constitute BART and note that the Department's determination is consistent with BART determinations throughout the western U.S. We believe that the determination of feasible control level is aggressive and concur with the Department that it is appropriate to determine compliance with the 0.23 lb/MMBtu heat input limit based on a rolling 12-month average.

NOx BART Compliance Schedule

PGE generally supports the NOx BART installation schedule, but notes that compliance with these deadlines is dependent on EPA approving the Regional Haze SIP and DEQ approving the necessary preconstruction permits in a timely manner. Because of the need to know with certainty that the SIP is approved and the need for preconstruction permits prior to commencing construction, PGE is faced with potentially critical delays beyond its control. In order to avoid PGE being placed in the untenable position of having to proceed with millions of dollars worth of controls in the absence of clear regulatory or permit authority, PGE requests that DEQ add language authorizing the Department to delay installation of the controls in the event of delays beyond PGE's reasonable control. We recognize that under federal law the Department cannot extend the compliance deadline by more than five years after EPA approves the portion of the SIP containing the NOx BART limits.

Neither PGE nor the Department can have absolute certainty that EPA will approve the Regional Haze SIP. Therefore, PGE believes that it is critical to add language to the proposed rules specifying that if the Regional Haze SIP provisions relating to the NOx BART determination is disapproved that PGE is not required to proceed with installation of the controls as a matter of state rule. If EPA disapproves the SIP provisions mandating controls, that agency will presumably require some other approach. Therefore, we suggest that the proposed rules provide a mechanism for staying the control requirements in the event that EPA disapproves the SIP provisions mandating controls.

3. Comments on Proposed SO_2 BART Rule

SO_2 BART Limit Determination

PGE supports the Department's SO_2 BART determination. The proposed SO_2 BART determination will reduce SO_2 from the Boardman plant by approximately 80% from current levels through the installation of a semi-dry scrubber system. While this technology comes at both a capital expense and generation efficiency penalty, we agree that these controls constitute BART and note that the Department's determination is consistent with or more aggressive than BART determinations throughout the western U.S. We concur with the Department that it is appropriate to determine compliance with the 0.12 lb/MMBtu heat input limit based on a rolling 30-day average basis.

SO_2 BART Compliance Schedule

PGE generally supports the SO_2 BART installation schedule, but notes that compliance with the deadline is also dependent on EPA approving the Regional Haze SIP and DEQ approving the necessary preconstruction permits in a timely manner. As noted above PGE needs to know with certainty that the SIP is approved and that it has all permits in hand prior to commencing construction of several hundred million dollars worth of control equipment. In addition, if EPA does not approve the portions of the Regional Haze SIP containing the SO_2 limits in a reasonable time frame then PGE will not have enough time to procure and install the controls. Therefore, we suggest that either DEQ change the installation deadline to be five years from the date of EPA approval of the relevant portions of the Regional Haze SIP or that DEQ add a provision to the rules extending the deadline to five years post-SIP approval in the event that EPA does not approve these portions of the SIP by the end of 2009.

Alternative SO_2 BART Determination

PGE also requests that DEQ add an alternative SO_2 BART determination to the proposed regulations. Section 169A(g) of the Clean Air Act specifies that BART determinations must take into account the remaining useful life of the BART eligible emission unit. See, also 40 CFR § 51.308(e)(1)(ii)(A). EPA stated that this factor should be accounted for in assessing the cost impacts of a particular control technology. 70 Fed. Reg. 39127 (July 6, 2005). In its November 2007 BART determination PGE noted that the possible premature cessation of operations of the coal-fired boiler may be appropriate for consideration in determining BART. Consistent with 40 CFR § 51, App Y Section IV(D)(4)(k) ("How do I take into account a project's 'remaining useful life' in calculating control costs"), PGE recognized the possibility that it might be necessary to include a regulatory scenario that anticipated the early closure of the Foster-Wheeler boiler. Based on the continued uncertainties about fuel cost/availability, replacement power, carbon regulation, control technologies and combustion technologies, PGE believes that

including an alternative to the proposed BART determination is appropriate. EPA specifically anticipated sources needing flexibility and seeking alternatives, and addressed this possibility in Section IV(D)(4)(k)(3) of 40 CFR § 51, App Y. In evaluating the cost-effectiveness of the proposed SO_2 controls, PGE assumed that the controls would be in place and operational for twenty years. As a result, the annualized capital cost was amortized over the full twenty-year life of the control device. We believe that it is consistent with the Clean Air Act and EPA's regulations to include an alternate BART determination for SO_2 that reflects a shorter facility life than the twenty-year life assumed in the current evaluation.

Incorporating an alternative SO_2 BART determination into the Oregon BART rules provides PGE the flexibility needed to best protect its customers while protecting the environment. PGE is requesting the option to assume a federally enforceable permit limit requiring cessation of the Foster-Wheeler boiler operations by the end of 2020 in lieu of installing the semi-dry scrubbers. In order to ensure adequate time to incorporate the permit limit into its permit as well as to ensure that the permit limit was in place prior to the 2014 deadline for installing the SO_2 controls, PGE would need to apply for this federally enforceable limit no later than July 1, 2012. If PGE submitted an application requesting the condition by that date, and responded in a timely fashion to any Department requests, PGE would be required to terminate operation of the Foster-Wheeler boiler by 2020. Alternatively, if PGE did not submit an application by July 1, 2012 requesting the permit limit, PGE would be bound by the Department's proposed SO_2 BART compliance deadlines and would have to install the semi-dry scrubbers by July 1, 2014. Both options, including the requirement to submit the permit limit application by July 1, 2012, would be placed in the rules. PGE, with guidance from the Oregon Public Utilities Commission (OPUC) and stakeholders, would then need to decide no later than July 1, 2012 whether to install the SO_2 BART controls or cease operating the Foster-Wheeler boiler by the end of 2020.

Incorporating the recommended alternative SO_2 BART determination with the 2012 decision point into the Oregon BART rules is consistent with all federal requirements. As noted above, not only is there no prohibition on the Department incorporating alternative BART options, Appendix Y to the federal BART regulations states that alternatives are permissible so long as each option independently meets the BART criteria. 40 CFR § 51, App Y, Section IV(D)(4)(k). The 2020 alternative BART determination clearly meets the BART criteria. As noted above, the Clean Air Act requires consideration of the remaining useful life of the plant. EPA's rules recognize that if the remaining useful life is limited by permit condition then the cost-effectiveness needs to be determined based on amortizing the capital cost over the reduced equipment life. The cost-effectiveness of the semi-dry scrubbers based on a useful life of 6.5 years (i.e., the number of years after July 1, 2014 that the control would be operated if the Foster-

Wheeler boiler ceased operation in 2020) is approximately $5,200 per ton of SO_2 controlled (see attached spreadsheet for details of cost-effectiveness evaluation).[3] This cost-effectiveness far exceeds the range of SO_2 cost-effectiveness evaluated by EPA in establishing the presumptive BART limits. In EPA's assessment they looked at costs ranging from $400/ton to $2,000/ton. The cost-effectiveness of the semi-dry scrubbers if operated only 6.5 years would be almost triple the high end of the range of what EPA considered cost-effective. Therefore, with only a 6.5-year operational life it is appropriate to consider BART to require no additional SO_2 controls so long as the Foster-Wheeler boiler is required to cease operation by the end of 2020. This determination would not affect the requirement to operate the NOx BART controls and nor would it affect PGE's obligation to control mercury emitted from the boiler.

It is also appropriate to consider the alternative SO_2 BART determination in light of the long term benefits to the environment provided by both options. If the plant installed the proposed BART controls (i.e., low-NOx burners, modified overfire air and semi-dry scrubbers) and operated through 2040, the aggregate visibility pollutant (i.e., NOx, SO_2 and PM) emissions calculated on a potential to emit basis would total 336,358 tons.[4] If the proposed NOx/SO_2 BART controls and SCR were installed, the aggregate visibility pollutant emissions through 2040 would total 237,149 tons. If NOx BART but no other controls were installed on the boiler and the boiler ceased operation at the end of 2020, 232,453 tons of visibility pollutants would be emitted. A comparison of the aggregate emissions is presented below.

Controls Installed	Boiler Operated Through	Total Visibility Pollutant Emissions (tons)			
		NOx	SO_2	PM	Aggregate
LNB/OFA	12/31/2020	63,588	158,311	10,554	232,453
LNB/OFA and SD scrubbers	12/31/2040	184,960	139,313	12,084	336,358
LNB/OFA, SD Scrubbers & SCR	12/31/2040	85,752	139,313	12,084	237,149

Notes: All computations start 1/1/2011; emissions calculations based on plant potential to emit.

[3] Section 4(k)(2) of Appendix Y specifies that the remaining useful life of a control is the difference between the date the controls would go into place and the date the controlled unit permanently stops operation.

[4] 2040 is the current projected life of the Foster-Wheeler boiler that was identified in PGE's BART analysis. However, there is no legal requirement to cease operation of the boiler at that time and the actual life of the boiler could be longer.

These suggested revisions are consistent with the BART requirements, are environmentally beneficial and also provide additional benefits. As the Department knows, the electrical generation business is in a time of tremendous transition. Over the next decade we anticipate tremendous advances in both electricity generation and control technology (e.g., carbon capture and sequestration). In addition, we anticipate that carbon will become subject to regulation. The full costs and benefits of these changes cannot be fully assessed at this time. However, by the time that PGE must decide whether to apply for its federally enforceable condition requiring cessation of operation of the Foster-Wheeler boiler or install the SO_2 BART controls, both PGE and the OPUC likely will have a better idea of the best future for the Boardman plant. As the Department knows, PGE is also regulated by the OPUC, and resource decisions such as the installation of BART controls must be fully vetted in the OPUC's Integrated Resource Planning (IRP) process. That process includes extensive public and stakeholder input and detailed modeling of resource decisions to yield the best combination of expected costs and risks. By building this decision point into the BART rules, it will help ensure that the decisions regarding Boardman are made with the most complete information. By enabling a more comprehensive and reasoned decision making process on the future of Boardman we also anticipate that DEQ will reduce the fiscal impacts to businesses in Oregon as compared to the Department's proposed BART rules.

Startup, Shutdown and Malfunction Exemption

We appreciate the recognition in the proposed rules that the technology based limits do not apply during startups and shutdowns. EPA was clear in the BART regulations that startups and shutdowns were not normal operating conditions and that the BART visibility impact assessment was intended to assess normal operating conditions. Therefore, we believe that it is appropriate to not include periods of startup and shutdown in determining compliance. However, it is equally true that the controls cannot be anticipated to perform as designed during a malfunction (defined under federal law, see, e.g. 40 CFR 63.2, as an upset that is not reasonably foreseeable or preventable and not resulting from inadequate design or maintenance). Therefore, we suggest that the regulations similarly note that malfunction periods should similarly not be included when evaluating whether the controls are operating properly and compliance is being achieved.

PM Limit Error

The proposed BART rule identifies the PM limit as 0.12 lb/MMBtu heat input, but PGE's BART determination and the Department's documentation indicate that it should read "0.012 lb/mmBtu heat input." We believe this was just a typographical error.

Recommended BART Rule Edits

For the reasons stated above, we request that section 1 of the proposed OAR 340-223-0030 (the Boardman BART rule) be revised as follows:

340-223-0030
BART Requirements for the Foster-Wheeler boiler at the Boardman Coal-Fired Power Plant (Federal Acid rain program facility ORISPL code 6106)
(1) Emissions limits:
(a) On and after July 1, 2011, nitrogen oxides emissions must not exceed 0.28 lb/mmBtu heat input as a 30-day rolling average and 0.23 lb/mmBtu heat input as a 12-month rolling average.
(A) If it is demonstrated by July 1, 2012 that the emission limits in (a) cannot be achieved with combustion controls, the Department may grant an extension of compliance to July 1, 2014.
(B) If an extension is granted, the nitrogen oxides emissions must not exceed 0.23 lb/mm Btu heat input as a 30-day rolling average on and after July 1, 2014.
(b) On and after July 1, 2014, sulfur dioxide emissions must not exceed 0.12 lb/mmBtu heat input as a 30-day rolling average.
(c) On and after July 1, 2014, particulate matter emissions must not exceed 0.012 lb/mmBtu heat input as determined by compliance source testing.
(d) The emission limits in (a) through (c) above do not apply during periods of startup, ~~or~~ shutdown or malfunction.
(e) The emission limits in (b) and (c) above do not apply if the operator has assumed a federally enforceable permit condition prior to July 1, 2014 requiring that the Foster-Wheeler boiler cease emissions by December 31, 2020. In order to ensure adequate time for the Department to process the permit modification by this deadline, the request for the federally enforceable permit condition must be submitted to the Department no later than July 1, 2012. If the permittee submits a permit application requesting the permit limit on or before July 1, 2012 and submits to all Department information requests associated with the application in a timely manner, the permittee shall be deemed to have the permit condition in place.
(f) The emission limits in (a), (b) and (c) above do not apply if EPA disapproves the portion of the Regional Haze SIP containing these limits or that portion of the Regional Haze SIP is otherwise invalidated.

> (g) If EPA fails to approve the portion of the Regional Haze SIP containing the emission limits and compliance deadlines in (b) and (c) above by December 31, 2009, then those deadlines shall automatically change to five years after approval of the portion of the Regional Haze SIP containing these limits and deadlines.
> (h) The Department may extend the deadlines in (a), (b) and (c) above to account for delays beyond the reasonable control of the permittee, including delays in the issuance of permits authorizing construction of the controls. The Department may not extend the compliance deadline more than five years after the date that EPA approves the portion of the Regional Haze SIP containing these limits and deadlines.

4. Comments on Proposed Reasonable Progress Rule

SCR Is Not Justified by Reasonable Progress Requirements

PGE has significant concerns regarding DEQ's proposal that SCR is required under the Reasonable Progress program. In the November 2007 BART determination report, PGE demonstrated that SCR is not BART for the Boardman boiler. The technology is not cost-effective, does not provide material benefits to visibility in the mandatory Class 1 areas and has material non-air quality environmental impacts. For all these reasons DEQ reasonably concluded that SCR is not BART. Section 169A(g)(1) of the federal Clean Air Act mandates that the same considerations must be applied in determining what constitutes Reasonable Progress controls. Therefore, for the same reasons that DEQ determined that SCR did not constitute BART, it should not consider SCR to be required by Reasonable Progress.

DEQ Has No Basis For Imposing Reasonable Progress Requirements on Boardman At This Time

PGE is similarly concerned about DEQ's choice to proceed at this time with a Reasonable Progress determination for the Boardman Plant while not considering Reasonable Progress for any other emission sources in Oregon. We are not aware of any other state in the western U.S. addressing additional controls under Reasonable Progress at this time. The Reasonable Progress assessment in the Department's proposed Regional Haze SIP states that "it is not reasonable to require controls" for any of the stationary source categories reviewed and notes that the Department will be developing guidance for conducting Reasonable Progress control

determinations over the next five years. Proposed Regional Haze Plan at 171. Putting aside the fact that for the reasons stated in the previous paragraph SCR does not meet the Reasonable Progress guidelines established by statute and EPA guidance, it is arbitrary for DEQ to single out one source for a program that is otherwise in its nascent stages and where no other source in the state is under consideration. For these reasons we propose that DEQ not include the Reasonable Progress component in the BART rules. DEQ can address Reasonable Progress for the Boardman plant when it develops its Reasonable Progress SIP for the state as a whole.

Alternative Reasonable Progress Determination

Even if DEQ were to proceed with Reasonable Progress at this time for the Boardman Plant and SCR was determined to constitute a Reasonable Progress control, we believe that DEQ should include an alternative determination similar to what is proposed above for BART. EPA's June 2007 EPA Reasonable Progress guidance states:

> "The fourth statutory factor is 'the remaining useful life of any existing source subject to [reasonable progress] requirements.' This factor is generally best treated as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *Air Pollution Control Cost Manual* require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life of the source will clearly exceed this time period, the remaining useful life factor has essentially no effect on control costs and on the reasonable progress determination process. Where the remaining useful life of the source is less than the time period for amortizing the costs of the retrofit control, you may wish to use this shorter time period in your cost calculations."

This statement supports a similar approach to that required under BART where a shorter facility life is taken into account when determining cost-effectiveness. In evaluating the cost-effectiveness of SCR, PGE assumed that the controls would be in place and operational for twenty years. As a result, the annualized capital cost was amortized over the full twenty-year life of the control device. We believe that it is consistent with the Clean Air Act and EPA's regulations to include an alternate Reasonable Progress determination for NOx that reflects a shorter facility life.

If DEQ proceeds with requiring SCR as Reasonable Progress, PGE recommends incorporating an option under which PGE may assume a federally enforceable permit limit requiring cessation of the Foster-Wheeler boiler operations by 2029. In order to ensure adequate time to incorporate the permit limit into its permit as well as to ensure that the permit limit is in place prior to the 2017 deadline currently proposed for installing SCR, PGE would need to apply for this federally enforceable limit no later than July 1, 2015. If PGE submitted an application requesting the condition by that date, and responded in a timely fashion to any Department requests, it would be required to terminate operation of the Foster-Wheeler boiler by 2029. Alternatively, if PGE did not submit an application by July 1, 2015 requesting the permit limit, PGE would be bound by the Department's proposed Reasonable Progress NOx control compliance deadline and would have to install SCR by July 1, 2017. Both options, including the requirement to submit the permit limit application by July 1, 2015, would be placed in the rules. PGE, with guidance from the OPUC and stakeholders, would then need to decide no later than July 1, 2015 whether to install SCR or cease operating the Foster-Wheeler boiler by the end of 2029.

Incorporating the recommended option into the Oregon Reasonable Progress rules is consistent with all federal requirements. As with BART, there is no prohibition on the Department incorporating alternative Reasonable Progress options so long as each option independently meets the Reasonable Progress criteria. The alternative Reasonable Progress option clearly meets all the statutory and regulatory criteria. As noted above, the Section 169A of the federal Clean Air Act requires consideration of the remaining useful life of the plant for both BART and Reasonable Progress determinations. EPA's rules recognize that if the remaining useful life is limited by permit condition then the cost-effectiveness needs to be determined based on amortizing the capital cost over the reduced equipment life. 40 CFR 51, App. Y Section IV(D)(4)(k). The cost-effectiveness of the SCR based on a useful life of 12.5 years (i.e., the number of years after July 1, 2017 that the control would be operated if the plant had to close by the end of 2029) is over $7,300 per ton of NO_x controlled. This cost-effectiveness far exceeds the range of NO_x cost-effectiveness evaluated by EPA in establishing the presumptive BART limits. In EPA's assessment they looked at costs ranging from $100/ton to $1,000/ton. The cost-effectiveness of the SCR if operated only 12.5 years would be over seven times greater than the high end range of what EPA considered cost-effective. Therefore, with only a 12.5-year operational life it is appropriate to consider the cessation of operation of the Foster-Wheeler boiler by the end of 2029 to constitute Reasonable Progress. This determination would not affect the requirement to operate the NOx and SO_2 BART controls and nor would it affect PGE's obligation to control mercury from the boiler.

It is also appropriate to consider the alternative of cessation of the Foster-Wheeler boiler operations at the end of 2029 to be Reasonable Progress in light of the long term benefits to the environment provided by both options. If the plant installed the proposed BART controls (i.e., low-NOx burners, modified overfire air and semi-dry scrubbers) and operated through 2040, the aggregate visibility pollutant emissions calculated on a potential to emit basis would total 336,358 tons. If the BART controls and SCR were installed, the aggregate visibility pollutant emissions through 2040 would total 237,149 tons. If the BART controls were installed on the boiler, no SCR was installed, and the boiler ceased operation at the end of 2029, then 231,292 tons of visibility pollutants would be emitted. By not installing the SCR, a material quantity of ammonia emissions would be avoided. A comparison of the aggregate emissions is presented below.

Controls Installed	**Boiler Operated Through**	**Total Emissions (tons)**			
		NOx	**SO_2**	**PM**	**Aggregate**
LNB/OFA and SD scrubbers	12/31/2029	118,208	104,485	8,602	231,292
LNB/OFA and SD scrubbers	12/31/2040	184,960	139,313	12,084	336,358
LNB/OFA, SD Scrubbers & SCR	12/31/2040	85,752	139,313	12,084	237,149

Notes: All computations start 1/1/2011; emissions calculations based on plant potential to emit.

These suggested revisions are consistent with the Reasonable Progress requirements, are environmentally beneficial and also provide additional benefits. As we discussed above, the electrical generation business is in a time of tremendous transition. Over the next decade we anticipate tremendous advances in both electricity generation and control technology (e.g., carbon capture and sequestration). In addition, we anticipate that carbon will become subject to regulation. The full costs and benefits of these changes cannot be fully assessed at this time. However, by the time that PGE must decide whether to apply for its federally enforceable condition requiring cessation of operation of the Foster-Wheeler boiler or install SCR, both PGE and the Oregon Public Utilities Commission will have a much better idea of the best future for the Boardman plant. By building this decision point into the Reasonable Progress rules, it is possible to ensure that the decisions regarding Boardman are made with the most complete information. By enabling a more comprehensive and reasoned decision making process on the future of Boardman we also anticipate that DEQ will reduce the fiscal impacts to businesses in Oregon as compared to the Department's proposed rulemaking.

Startup, Shutdown and Malfunction Exemption

As noted above in relation to the BART controls we appreciate the recognition in the proposed rules that the technology based Reasonable Progress limit does not apply during startups and shutdowns. EPA was clear in the BART regulations that startups and shutdowns were not normal operating conditions and that the BART visibility impact assessment was intended to assess normal operating conditions. Therefore, we believe that it is appropriate to not include periods of startup and shutdown in determining compliance. However, it is equally true that the controls cannot be anticipated to perform as designed during a malfunction (defined under federal law as an upset that is not reasonably foreseeable or preventable and not resulting from inadequate design or maintenance). Therefore, we suggest that the regulations similarly note that malfunction periods should similarly not be included when evaluating whether the controls are operating properly and compliance is being achieved.

For the reasons stated above, we request that the proposed OAR 340-223-0040 (the Boardman Reasonable Progress rule) be revised as follows:

340-223-0040

Additional NO_x Requirements for the Foster-Wheeler boiler at the Boardman Coal-Fired Power Plant (Federal Acid rain program facility ORISPL code 6106)

(1) On and after July 1, 2017, nitrogen oxides emissions must not exceed 0.070 lb/mmBtu heat input, excluding periods of startup, ~~or~~ shutdown or malfunction.

(a) Compliance with the NOx emissions limit must be determined with a continuous emissions monitoring system in accordance with OAR 340-223-0030(2) and (3).

(b) The Department must be notified in writing within 7 days after any control equipment used to comply with the emission limit begins operation.

(c) A compliance status report, including CEMS data, must be submitted by January 1, 2018.

(d) The emission limit in (1) above does not apply if the operator has assumed a federally enforceable permit condition prior to July 1, 2017 requiring that the Foster-Wheeler boiler cease emissions by December 31, 2029. In order to ensure adequate time for the Department to process the permit modification by this deadline, the request for the federally enforceable permit condition must be submitted to the Department no later than July 1, 2015. If the permittee submits a permit application

requesting the permit limit on or before July 1, 2015 and submits to all Department information requests associated with the application in a timely manner, the permittee shall be deemed to have the permit condition in place.
(e) The emission limit in (1) above does not apply if EPA disapproves the portion of the Regional Haze SIP containing that limit or that portion of the Regional Haze SIP is otherwise invalidated.
(f) If EPA fails to approve the portion of the Regional Haze SIP containing the emission limit and compliance deadline in (1) above by December 31, 2009, then those deadlines shall automatically change to eight years after approval of the portion of the Regional Haze SIP containing these limits and deadlines.

5. Conclusion

Attached please find spreadsheets documenting the cost-effectiveness values stated in our comments above as well as the comparative emissions between the different BART and Reasonable Progress alternatives. Please consider these spreadsheets to be an addendum to our November 2007 report. You will also find a flow diagram that visually presents the proposed alternative BART and Reasonable Progress determinations.

Thank you for your consideration of these comments. As you know, the OPUC and PGE must engage in a public IRP process that includes considering alternatives to the emission controls. By incorporating the BART and Reasonable Progress alternatives discussed above DEQ will better align the DEQ and OPUC processes. This protects the best interests of PGE, its customers and the Oregon economy while also satisfying all state and federal requirements, including protection of Oregon air quality. Therefore, we believe that it provides an important improvement to the proposed rules. We hope that DEQ will recognize these benefits, incorporate our suggested edits into the proposed rule and re-notice the package so as to enable the greatest degree of public participation.

Mr. Brian Finneran
December 17, 2008
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Please contact me if you have any questions or would like to discuss these comments further.

Sincerely,

Arya Behbehani-Divers

cc: Stephen Quennoz
Loren Mayer

Attachments: Tables 1-4
Flow Diagram

Table 1 - Cost Effectiveness Calculations for Alternative Evaluation Periods

SCR Cost Effectiveness Calculations for Reasonable Progress (NO_x)	
End of Evaluation Period, end of year	2,029
Years of Operation post-July 2017	12.5
Capital Recovery Factor (%)	12.27
Annualized Cost of SCR (1000$) after LNB/OFA in 2011	28,446
Reduced NO_x Emissions for SCR after LNB/OFA (tons/yr)	3,890
Cost Effectiveness of SCR ($/ton) after LNB/OFA in 2011	**7,312**

Semi-Dry FGD Cost Effectiveness Calculations for BART (SO_2)	
End of Evaluation Period, end of year	2,020
Years of Operation post-July 2014	6.5
Capital Recovery Factor (%)	19.68
Annualized Cost of Semi-Dry FGD (1000$)	61,935
Reduced SO_2 Emissions (tons/yr)	11,988
Cost Effectiveness of Semi-Dry FGD ($/ton)	**5,167**

Table 2 - LNB/OFA Installed in 2011 (No SDA//FF or SCR)

Year	NOx		SO2		PM		Total Annual Aggregate	Total Cumulative
	lb/MMBTU [a]	Tons [d]	lb/MMBTU [b]	Tons [d]	lb/MMBTU [c]	Tons [d]		
1st half of 2011	0.45	5,937	0.60	7,916	0.04	528	14,380	14,380
LNB/OFA Installed								
2nd half of 2011	0.23	3,034	0.60	7,916	0.04	528	11,478	25,857
2012	0.23	6,069	0.60	15,831	0.04	1,055	22,955	48,812
2013	0.23	6,069	0.60	15,831	0.04	1,055	22,955	71,768
2014	0.23	6,069	0.60	15,831	0.04	1,055	22,955	94,723
2015	0.23	6,069	0.60	15,831	0.04	1,055	22,955	117,678
2016	0.23	6,069	0.60	15,831	0.04	1,055	22,955	140,633
2017	0.23	6,069	0.60	15,831	0.04	1,055	22,955	163,588
2018	0.23	6,069	0.60	15,831	0.04	1,055	22,955	186,543
2019	0.23	6,069	0.60	15,831	0.04	1,055	22,955	209,498
2020	0.23	6,069	0.60	15,831	0.04	1,055	22,955	232,453
Proposed Shutdown								
2021	0.23	6,069	0.60	15,831	0.04	1,055	22,955	255,408
2022	0.23	6,069	0.60	15,831	0.04	1,055	22,955	278,363
2023	0.23	6,069	0.60	15,831	0.04	1,055	22,955	301,318
2024	0.23	6,069	0.60	15,831	0.04	1,055	22,955	324,273
2025	0.23	6,069	0.60	15,831	0.04	1,055	22,955	347,228
2026	0.23	6,069	0.60	15,831	0.04	1,055	22,955	370,183
2027	0.23	6,069	0.60	15,831	0.04	1,055	22,955	393,138
2028	0.23	6,069	0.60	15,831	0.04	1,055	22,955	416,093
2029	0.23	6,069	0.60	15,831	0.04	1,055	22,955	439,048
2030	0.23	6,069	0.60	15,831	0.04	1,055	22,955	462,003
2031	0.23	6,069	0.60	15,831	0.04	1,055	22,955	484,959
2032	0.23	6,069	0.60	15,831	0.04	1,055	22,955	507,914
2033	0.23	6,069	0.60	15,831	0.04	1,055	22,955	530,869
2034	0.23	6,069	0.60	15,831	0.04	1,055	22,955	553,824
2035	0.23	6,069	0.60	15,831	0.04	1,055	22,955	576,779
2036	0.23	6,069	0.60	15,831	0.04	1,055	22,955	599,734
2037	0.23	6,069	0.60	15,831	0.04	1,055	22,955	622,689
2038	0.23	6,069	0.60	15,831	0.04	1,055	22,955	645,644
2039	0.23	6,069	0.60	15,831	0.04	1,055	22,955	668,599
2040	0.23	6,069	0.60	15,831	0.04	1,055	22,955	691,554

Calculations:

(a) NOx emission rate (lb/MMBTU) = [2007 NOx emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 NOx emissions (tons) = 10,656 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(b) SO2 emission rate (lb/MMBTU) = [2007 SO2 emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 SO2 emissions (tons) = 14,037 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(c) PM emission rate (lb/MMBTU) = [2007 PM emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 PM emissions (tons) = 853 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(d) Annual emissions (tons/yr) = [emission rate (lb/MMBTU)] * [2007 hourly heat input (MMBTU/hr)] * [future operating hours (hours)] /2000

2007 Heat Input (MMBtu/hr) = 6,024 (3)
Future Operating Hours 8,760

Notes:

(1) Portland General Electric's 2007 Annual Title V Report
(2) US EPA Clean Air Markets
(3) Based on US EPA Clean Air Markets reported annual heat input / 2007 annual operating hours (7,787)

Table 3 - LNB/OFA Installed in 2011, SDA/FF Installed in 2014 (No SCR)

Year	NOx lb/MMBTU [a]	NOx Tons [d]	SO2 lb/MMBTU [b]	SO2 Tons [d]	PM lb/MMBTU [c]	PM Tons [d]	Total Annual Aggregate	Total Cumulative
1st half of 2011	0.45	5,937	0.60	7,916	0.04	528	14,380	14,380
				LNB/OFA Installed				
2nd half of 2011	0.23	3,034	0.60	7,916	0.04	528	11,478	25,857
2012	0.23	6,069	0.60	15,831	0.04	1,055	22,955	48,812
2013	0.23	6,069	0.60	15,831	0.04	1,055	22,955	71,768
1st half of 2014	0.23	3,034	0.60	7,916	0.04	528	11,478	83,245
				SDA/FF Installed				
Second half of 2014	0.23	3,034	0.12	1,583	0.012	158	4,776	88,021
2015	0.23	6,069	0.12	3,166	0.012	317	9,551	97,572
2016	0.23	6,069	0.12	3,166	0.012	317	9,551	107,124
2017	0.23	6,069	0.12	3,166	0.012	317	9,551	116,675
2018	0.23	6,069	0.12	3,166	0.012	317	9,551	126,226
2019	0.23	6,069	0.12	3,166	0.012	317	9,551	135,778
2020	0.23	6,069	0.12	3,166	0.012	317	9,551	145,329
2021	0.23	6,069	0.12	3,166	0.012	317	9,551	154,881
2022	0.23	6,069	0.12	3,166	0.012	317	9,551	164,432
2023	0.23	6,069	0.12	3,166	0.012	317	9,551	173,983
2024	0.23	6,069	0.12	3,166	0.012	317	9,551	183,535
2025	0.23	6,069	0.12	3,166	0.012	317	9,551	193,086
2026	0.23	6,069	0.12	3,166	0.012	317	9,551	202,638
2027	0.23	6,069	0.12	3,166	0.012	317	9,551	212,189
2028	0.23	6,069	0.12	3,166	0.012	317	9,551	221,741
2029	0.23	6,069	0.12	3,166	0.012	317	9,551	231,292
				Proposed Shutdown				
2030	0.23	6,069	0.12	3,166	0.012	317	9,551	240,843
2031	0.23	6,069	0.12	3,166	0.012	317	9,551	250,395
2032	0.23	6,069	0.12	3,166	0.012	317	9,551	259,946
2033	0.23	6,069	0.12	3,166	0.012	317	9,551	269,498
2034	0.23	6,069	0.12	3,166	0.012	317	9,551	279,049
2035	0.23	6,069	0.12	3,166	0.012	317	9,551	288,600
2036	0.23	6,069	0.12	3,166	0.012	317	9,551	298,152
2037	0.23	6,069	0.12	3,166	0.012	317	9,551	307,703
2038	0.23	6,069	0.12	3,166	0.012	317	9,551	317,255
2039	0.23	6,069	0.12	3,166	0.012	317	9,551	326,806
2040	0.23	6,069	0.12	3,166	0.012	317	9,551	336,358

Calculations:

(a) NOx emission rate (lb/MMBTU) = [2007 NOx emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 NOx emissions (tons) = 10,656 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(b) SO2 emission rate (lb/MMBTU) = [2007 SO2 emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 SO2 emissions (tons) = 14,037 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(c) PM emission rate (lb/MMBTU) = [2007 PM emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000

2007 PM emissions (tons) = 853 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(d) Annual emissions (tons/yr) = [emission rate (lb/MMBTU)] * [2007 hourly heat input (MMBTU/hr)] * [future operating hours (hours)] / 2000

2007 Heat Input (MMBtu/hr) = 6,024 (3)
Future Operating Hours 8,760

Notes:

(1) Portland General Electric's 2007 Annual Title V Report
(2) US EPA Clean Air Markets
(3) Based on US EPA Clean Air Markets reported annual heat input / 2007 annual operating hours (7,787)

Table 4 - LNB/OFA Installed in 2011, SDA/FF Installed in 2014, and SCR Installed in 2017

Year	NOx		SO2		PM		Total Annual Aggregate	Total Cumulative
	lb/MMBTU [a]	Tons [d]	lb/MMBTU [b]	Tons [d]	lb/MMBTU [c]	Tons [d]		
1st half of 2011	0.45	5,937	0.60	7,916	0.04	528	14,380	14,380
LNB/OFA Installed								
2nd half of 2011	0.23	3,034	0.60	7,916	0.04	528	11,478	25,857
2012	0.23	6,069	0.60	15,831	0.04	1,055	22,955	48,812
2013	0.23	6,069	0.60	15,831	0.04	1,055	22,955	71,768
1st half of 2014	0.23	3,034	0.60	7,916	0.04	528	11,478	83,245
SDA/FF Installed								
Second half of 2014	0.23	3,034	0.12	1,583	0.012	158	4,776	88,021
2015	0.23	6,069	0.12	3,166	0.012	317	9,551	97,572
2016	0.23	6,069	0.12	3,166	0.012	317	9,551	107,124
1st half of 2017	0.23	3,034	0.12	1,583	0.012	158	4,776	111,899
SCR Installed								
2nd half of 2017	0.07	923	0.12	1,583	0.012	158	2,665	114,564
2018	0.07	1,847	0.12	3,166	0.012	317	5,330	119,894
2019	0.07	1,847	0.12	3,166	0.012	317	5,330	125,224
2020	0.07	1,847	0.12	3,166	0.012	317	5,330	130,554
2021	0.07	1,847	0.12	3,166	0.012	317	5,330	135,883
2022	0.07	1,847	0.12	3,166	0.012	317	5,330	141,213
2023	0.07	1,847	0.12	3,166	0.012	317	5,330	146,543
2024	0.07	1,847	0.12	3,166	0.012	317	5,330	151,873
2025	0.07	1,847	0.12	3,166	0.012	317	5,330	157,203
2026	0.07	1,847	0.12	3,166	0.012	317	5,330	162,532
2027	0.07	1,847	0.12	3,166	0.012	317	5,330	167,862
2028	0.07	1,847	0.12	3,166	0.012	317	5,330	173,192
2029	0.07	1,847	0.12	3,166	0.012	317	5,330	178,522
2030	0.07	1,847	0.12	3,166	0.012	317	5,330	183,852
2031	0.07	1,847	0.12	3,166	0.012	317	5,330	189,181
2032	0.07	1,847	0.12	3,166	0.012	317	5,330	194,511
2033	0.07	1,847	0.12	3,166	0.012	317	5,330	199,841
2034	0.07	1,847	0.12	3,166	0.012	317	5,330	205,171
2035	0.07	1,847	0.12	3,166	0.012	317	5,330	210,500
2036	0.07	1,847	0.12	3,166	0.012	317	5,330	215,830
2037	0.07	1,847	0.12	3,166	0.012	317	5,330	221,160
2038	0.07	1,847	0.12	3,166	0.012	317	5,330	226,490
2039	0.07	1,847	0.12	3,166	0.012	317	5,330	231,820
2040	0.07	1,847	0.12	3,166	0.012	317	5,330	237,149

Calculations:

(a) NOx emission rate (lb/MMBTU) = [2007 NOx emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000
2007 NOx emissions (tons) = 10,656 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(b) SO2 emission rate (lb/MMBTU) = [2007 SO2 emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000
2007 SO2 emissions (tons) = 14,037 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

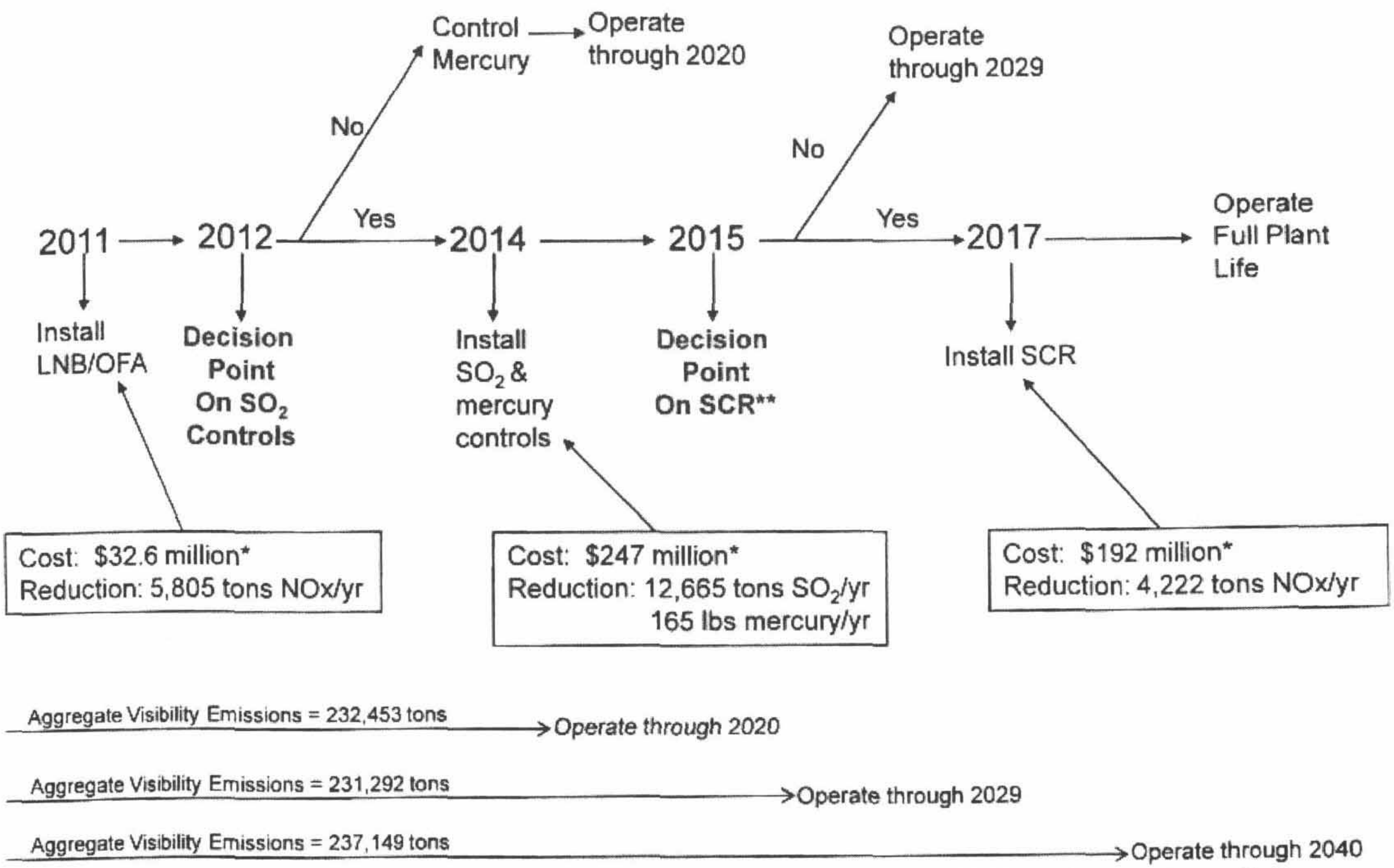
(c) PM emission rate (lb/MMBTU) = [2007 PM emissions (tons)] / [2007 annual heat input (MMBtu)] * 2000
2007 PM emissions (tons) = 853 (1)
2007 Heat Input (MMBtu) = 46,913,216 (2)

(d) Annual emissions (tons/yr) = [emission rate (lb/MMBTU)] * [2007 hourly heat input (MMBTU/hr)] * [future operating hours (hours)] / 2000
2007 Heat Input (MMBtu/hr) = 6,024 (3)
Future Operating Hours 8,760

Notes:

(1) Portland General Electric's 2007 Annual Title V Report
(2) US EPA Clean Air Markets
(3) Based on US EPA Clean Air Markets reported annual heat input / 2007 annual operating hours (7,787)

PGE Alternative Boardman BART/Reasonable Progress Proposal



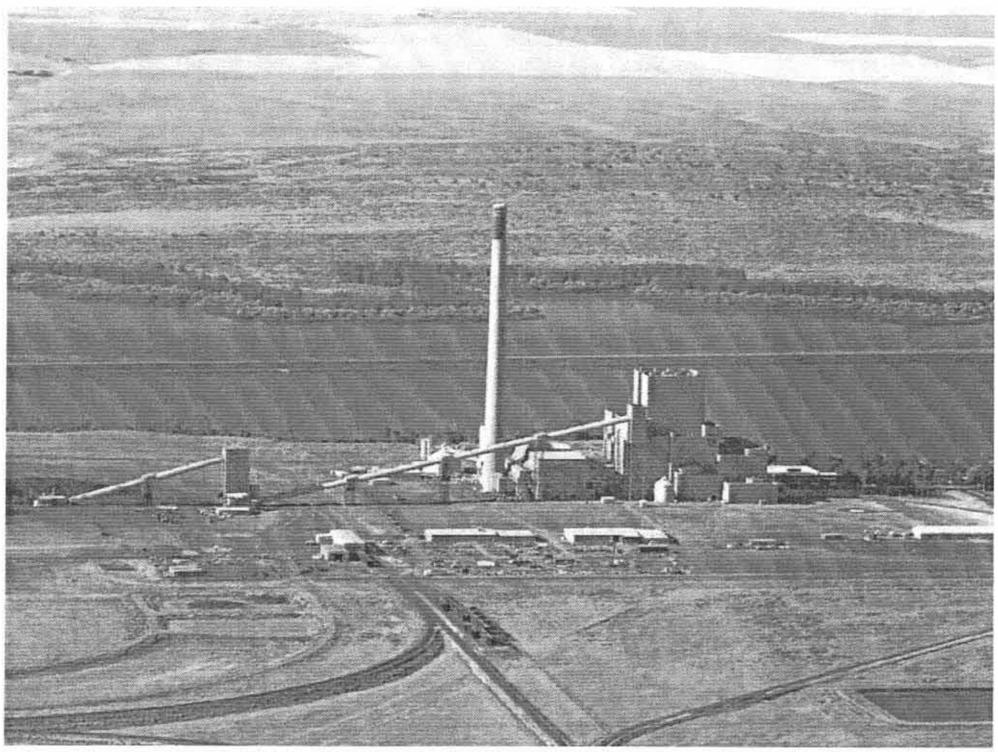
*Estimates are of full control cost in 2007 dollars

**Assumes that SCR is required under Reasonable Progress

Portland General Electric

Boardman Plant

Best Available Retrofit Technology (BART) Analysis



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November 2, 2007

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Executive Summary

The Boardman Plant is a 584 megawatt (MW) net pulverized coal fired steam electric plant of more than 250 million British thermal unit (MMBTU) per hour heat input located near Boardman, Oregon, about 150 miles east of Portland. The plant was issued its construction authorization on February 27, 1975 by the Oregon Nuclear and Thermal Energy Council.

On July 6, 2005, the Environmental Protection Agency (EPA) issued its final *Regional Haze Regulations and Guidelines for Performing Best Available Retrofit Technology (BART) Determinations*. These rules/guidelines established a procedure for identifying those sources that must retrofit their existing facilities with BART and for determining what constitutes BART. The purpose of the BART program was to require controls, where appropriate, for facilities that were "grandfathered" from the new source review requirements of the 1977 Clean Air Act Amendments. Specifically, the BART rules apply exclusively to sources within one of the enumerated source categories that were in existence prior to August 7, 1977.

Because the Boardman Plant is a steam electric plant of more than 250 MMBTU per hour heat input that was in existence (as that term is defined by EPA) before August 7, 1977, it was identified by the Oregon Department of Environmental Quality (DEQ) as a BART source. Portland General Electric (PGE) volunteered to serve as the pilot source for DEQ's BART determination process. This analysis has been prepared in accordance with the five-step process identified in the EPA's *Regional Haze Regulations and Guidelines for Performing BART Determinations* (40 CFR Part 51, Appendix Y) to evaluate the best available retrofit control technologies for the reduction of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and particulate matter (PM) emissions from the Boardman Plant.

The five-step BART analysis was used to generate the information needed to identify the best control technology package that constitutes BART for the Boardman Plant. In Step 1, available NO_x, SO_2, and PM retrofit control technologies were identified for the Boardman Plant. In Step 2, this list was shortened by eliminating those technologies that are not considered technically feasible. In Step 3, the control effectiveness of each technically feasible control technology was evaluated and, based on this evaluation, the technologies were ranked in order of effectiveness. In Step 4, the cost, energy, and environmental impacts were evaluated for each technically feasible control technology. In the final step, the visibility improvements associated with the top-ranked options were evaluated consistent with the modeling protocol approved by DEQ on January 18, 2007 and amended on August 28, 2007.

NO_x Control Selection

After all of the statutory factors were considered, the NO_x controls combination of new low NO_x burners with modified overfire air and selective noncatalytic reduction (NLNB/MOFA/SNCR) was identified as the Best Available Retrofit Technology for NO_x control. This NO_x control combination results in significant modeled visibility improvement at the Class 1 areas for Boardman Plant impacts.

An alternative NO_x control package that utilizes selective catalytic reduction (SCR) in lieu of SNCR was considered, but ultimately determined to have excessive impacts and so eliminated from consideration as BART. The controls combination of new LNBs with modified OFA and SCR (NLNB/MOFA/SCR) would result in greater NO_x reductions and slightly better modeled visibility improvements than NLNB/MOFA/SNCR. However, as EPA recognized in the 2005 preamble, the modeling system required for evaluating visibility impacts magnifies and overstates those impacts. Therefore, the small incremental improvement between the NO_x controls incorporating SNCR and the NO_x controls incorporating SCR is not, by itself, determinative. In addition, the use of the NO_x controls incorporating SCR has other impacts that are more severe than new LNBs with modified OFA system and SNCR. Specifically, the non-air quality environmental impacts (i.e., hazardous material disposal during catalyst replacement) and the energy impacts (i.e., significant fan auxiliary power to overcome additional system resistance) associated with NLNB/MOFA/SCR are higher than for NLNB/MOFA/SNCR.

The economic impacts also support selecting NLNB/MOFA/SNCR as BART. The economic impacts associated with the NLNB/MOFA/SCR alternative are considerably higher than the economic impacts associated with the NLNB/MOFA/SNCR alternative. The total capital cost of the NO_x controls incorporating SNCR is approximately $50 million while the total capital cost associated with the NO_x controls including SCR is approximately $223 million. Operating costs are similarly much higher with the SCR alternative than the SNCR alternative ($5.7 million per year as opposed to $2.4 million per year). However, the visibility improvements associated with the NO_x controls incorporating SCR are not commensurate with the additional $173 million in capital cost (as compared to the NO_x controls incorporating SNCR). Even if the plant were assumed to operate at its highest daily emission rate for every day of the year (something that never occurs), the use of the NO_x control package with SCR as opposed to that with SNCR, would result in only 7 fewer days per year where Mt Hood Wilderness Area visibility impacts exceeded 0.5 deciviews. The additional $173 million capital cost and $3.3 million per year of operating cost associated with the SCR control

package is not justified by the minimal benefit. This limited benefit carries across all of the Class I areas. The average 98th percentile impact level across all the Class I areas is only 0.27 deciviews better with the control option incorporating SCR than the control option incorporating SNCR. This equates to an incremental annualized control cost associated with moving from the NO_x controls with SNCR to the NO_x controls with SCR of approximately $72 million per deciview (based on an annualized cost of $27 million/year for package with SCR v. $7 million per year for package with SNCR). Again, the minimal improvement in visibility associated with the NO_x control option incorporating SCR does not justify the extreme incremental cost. This conclusion is confirmed through reference to the EPA cost-effectiveness recommendations. The cost effectiveness of the NO_x control package incorporating SCR ($3,096/ton) is significantly higher than the range ($100 to $1000/ton) considered reasonable in EPA's BART guidelines.

Consideration of the impact of requiring SCR on plant viability also supports the conclusion that BART for NO_x constitutes the control package with SNCR. The EPA Guidelines state that it is appropriate to take into account the affordability of particular controls as part of the BART analysis where the cost of installing and operating the controls is judged to have a severe impact on plant operations. That would be the case were BART considered to include SCR. The Boardman Plant is a key resource for providing baseload power to the region throughout the year. The imposition of SCR as BART, on top of the $300 million in air pollution control capital investments being proposed, could possibly require an investment in excess of what the plant can support. Under such circumstances the EPA Guidelines state that it is appropriate to consider the non-affordability of SCR and to therefore conclude that SCR is not BART. Based on the discussion within this report there is no need to rely on this factor to conclude that BART does not include SCR. However, this additional consideration lends further support to the conclusion that BART for NO_x constitutes the control package with SNCR.

From a design standpoint, since the Boardman boiler was not designed with space in the ductwork or with an appropriate temperature profile for utilization of SCR, very challenging and complex modifications to the boiler would be required at significant cost to lower the gas path temperature to the desired range while maintaining combustion efficiency. Therefore, a balancing of the statutory factors strongly supports NLNB/MOFA/SNCR as the best alternative.

SO_2 Control Selection

After all of the statutory factors were considered, the semi-dry flue gas desulfurization (semi-dry FGD) technology was determined to be the best BART alternative for SO_2 control. The two top SO_2 control technologies (wet FGD and semi-dry FGD) were modeled as having essentially the same level of visibility improvement at the Class I areas. However, the non-air quality environmental impacts and negative energy impacts are significantly greater for the wet FGD control technology, since it generates a visible plume, consumes more water, generates a wastewater stream requiring treatment and disposal, generates slightly more solid byproducts for landfill, and because the wet FGD requires significantly more auxiliary power consumption during operation. The economic impacts associated with the wet FGD are also much higher than the economic impacts associated with the semi-dry FGD. The costs associated with installing semi-dry FGD are very high, with a total capital cost of approximately $247 million and operating costs of approximately $13 million per year. While these costs are extremely high, the costs of the wet FGD system would be considerably higher with a total capital cost of approximately $382 million and operating costs of approximately $16 million per year. As a result, the cost effectiveness of the wet FGD control option is significantly higher than the range ($400 to $2000/ton) considered to be reasonable in EPA's BART guidelines. Given that wet FGD does not perform materially better than semi-dry FGD, there is no basis for spending the additional $135 million in capital and $3 million per year in operating expenses to implement the wet FGD technology. Therefore, consistent with the statutory factors, semi-dry FGD was chosen as the best alternative for SO_2 control.

Particulate (PM) Control Selection

After all of the statutory factors were considered, the pulse jet fabric filter (PJFF), in combination with the existing ESP, was determined to be the best BART control alternative for PM. Multiple technologies had equal control effectiveness, but the utilization of PJFF enables the highest level of mercury control. This improvement to water quality from reduction of mercury bioaccumulation is a significant positive environmental benefit and, therefore, supports the choice of PJFF as BART.

Best Control Combination Selection

The package of the selected controls (NLNB/MOFA/SNCR for NO_x and semi-dry FGD including PJFF for SO_2 and PM) constitutes BART for the Boardman Plant. This also constitutes the most effective package for integration with the controls being

designed for the Boardman Plant to meet the Oregon mercury standards for coal fired power plants.

While the Columbia River Gorge National Scenic Area (CRGNSA) is not a Class I area and so not a part of the BART analysis, there was interest in the benefits to that area as a result of the proposed BART controls. The modeling of the benefits predicted from the proposed BART control package show significant improvement in visibility in the CRGNSA. While slightly greater improvements are shown by the model from the use of a control package that includes SCR, these improvements are not considered significant. This conclusion was independently verified in the draft *Columbia River Gorge Air Quality Study Science Summary Report* (September 27, 2007) prepared by DEQ in conjunction with other state and federal governmental authorities. The report authors compared CRGNSA visibility as a result of the proposed BART controls (i.e., NLNB/MOFA/SNCR, semi-dry FGD and PJFF) to CRGNSA visibility if Boardman emissions were reduced to "0" (i.e., complete shutdown of the plant). As the report notes, "practically zero" additional visibility benefit is achieved by reducing plant emissions from those achieved by the proposed BART control package all the way to zero plant emissions.

That assessment serves as independent verification of the conclusion that no material visibility benefit would be gained by controlling NO_x through the use of new LNB with modified OFA and SCR rather than new LNB with modified OFA and SNCR. If eliminating the Boardman Plant generates "practically zero" additional benefit as compared to the proposed BART control package, the much smaller incremental benefit achieved by requiring SCR rather than SNCR would be immaterial. Given the extreme incremental cost associated with the use of new LNB with modified OFA and SCR for NO_x control, there is no technically sound basis for requiring SCR as part of the BART control package.

PGE's implementation of the suite of BART controls identified through this report will cost more than $297 million dollars to install and approximately $15 million per year to operate. While this poses a significant economic impact to the Boardman Plant and to Northwest electric utility customers, the controls are predicted to improve the plant's modeled worst-case visibility impacts in the Class I areas by an average 64 percent, improve the plant's modeled worst-case visibility impacts at the most severely impacted Class I area by 56 percent, and enable the enhanced control of mercury emissions. Therefore, the utilization of the NLNB/MOFA/SNCR and semi-dry FGD (including PJFF) is the best alternative and constitutes BART.

The following appendices contain supporting data for the BART analysis described in this report:

- Appendix A Design Basis.
- Appendix B Stack Outlet Conditions.
- Appendix C Design Concept Definitions.
- Appendix D Cost Analysis Summary.
- Appendix E Visibility Modeling Results.
- Appendix F Visibility Modeling Protocol.
- Appendix G Emissions Performance Analysis Memo.

Appendix D
Cost Analysis Summary

Technology: Overfire Air System Operation **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
Neural network system for NOx optimization	$345,000	B&V cost estimate		
NOx monitoring equipment	$182,000	B&V cost estimate		
Water cannon system	$1,452,000	B&V cost estimate		
Subtotal capital cost (CC)	$1,979,000			
Freight	$99,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$2,078,000			
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$416,000	(PEC) X	20.0%	
Electrical	$312,000	(PEC) X	15.0%	
Piping	$42,000	(PEC) X	2.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$52,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$822,000			
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$2,900,000			
Indirect Costs				
Engineering	$348,000	(DC) X	12.0%	
Owner's cost	$58,000	(DC) X	2.0%	
Construction management	$145,000	(DC) X	5.0%	
Start-up and spare parts	$58,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$290,000	(DC) X	10.0%	
Total indirect costs (IC)	$949,000			
Allowance for Funds Used During Construction (AFDC)	$173,000	[(DC)+(IC)]	8.99%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$4,022,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$87,000	(DC) X	3.0%	
Total fixed annual costs	$87,000			
Variable annual costs				
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh		
Total variable annual costs	$540,000			
Total direct annual costs (DAC)	$627,000			
Indirect Annual Costs				
Cost for capital recovery	$380,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$380,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,007,000**			

Technology: Overfire Air System Operation **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis
CAPITAL COST		
Direct Costs		
Purchased equipment costs		
Neural network system for NOx optimization	$345,000	B&V cost estimate
NOx monitoring equipment	$182,000	B&V cost estimate
Water cannon system	$1,452,000	B&V cost estimate
Subtotal capital cost (CC)	$1,979,000	
Freight	$99,000	(CC) X 5.0%
Total purchased equipment cost (PEC)	$2,078,000	(Ai)
Direct installation costs		
Foundation & supports	$0	(PEC) X 0.0%
Handling & erection	$416,000	(PEC) X 20.0%
Electrical	$312,000	(PEC) X 15.0%
Piping	$42,000	(PEC) X 2.0%
Insulation	$0	(PEC) X 0.0%
Painting	$0	(PEC) X 0.0%
Demolition	$52,000	(PEC) X 2.5%
Relocation	$0	(PEC) X 0.0%
Total direct installation costs (DIC)	$822,000	(Bi)
Site preparation	$0	N/A
Buildings	$0	N/A
Total direct costs (DC) = (PEC) + (DIC)	$2,900,000	(B)
Indirect Costs		
Engineering	$348,000	(DC) X 12.0%
Owner's cost	$58,000	(DC) X 2.0%
Construction management	$145,000	(DC) X 5.0%
Start-up and spare parts	$58,000	(DC) X 2.0%
Performance test	$50,000	Engineering estimate
Contingencies	$290,000	(DC) X 10.0%
Total indirect costs (IC)	$949,000	
Allowance for Funds Used During Construction (AFDC)	$173,000	[(DC)+(IC)] 8.99% 1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$4,022,000**	
ANNUAL COST		
Direct Annual Costs		
Fixed annual costs		
Maintenance labor and materials	$87,000	(DC) X 3.0%
Total fixed annual costs	$87,000	
Variable annual costs		
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh
Total variable annual costs	$540,000	
Total direct annual costs (DAC)	$627,000	
Indirect Annual Costs		
Cost for capital recovery	$380,000	(TCI) X 9.44% CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$380,000	
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,007,000**	

Technology: Upgraded Low NOx Burners

Date: 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
New coal elbow, nozzle with air vane, fuel injector barrel, air zone swirler and coal piping	$2,753,000	from vendor quote, 06/30/06		
Dynamic classifier for coal pulverizers	$1,760,000	B&V cost estimate		
Coal/air flow instrument for burners	$935,000	B&V cost estimate		
Subtotal capital cost (CC)	$5,448,000			
Freight	$272,000	(CC) X	5.0%	
Total purchased equipment cost (PEC)	$5,720,000	(A2)		
Direct installation costs				
Foundation & supports	$0	(PEC) X	0.0%	
Handling & erection	$1,144,000	(PEC) X	20.0%	
Electrical	$572,000	(PEC) X	10.0%	
Piping	$0	(PEC) X	0.0%	
Insulation	$0	(PEC) X	0.0%	
Painting	$0	(PEC) X	0.0%	
Demolition	$143,000	(PEC) X	2.5%	
Relocation	$0	(PEC) X	0.0%	
Total direct installation costs (DIC)	$1,859,000	(B2)		
Site preparation	$0	N/A		
Buildings	$0	N/A		
Total direct costs (DC) = (PEC) + (DIC)	$7,579,000	(C2)		
Indirect Costs				
Engineering	$909,000	(DC) X	12.0%	
Owner's cost	$152,000	(DC) X	2.0%	
Construction management	$379,000	(DC) X	5.0%	
Start-up and spare parts	$152,000	(DC) X	2.0%	
Performance test	$50,000	Engineering estimate		
Contingencies	$758,000	(DC) X	10.0%	
Total indirect costs (IC)	$2,400,000			
Allowance for Funds Used During Construction (AFDC)	$449,000	[(DC)+(IC)]	8.99%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$10,428,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Maintenance labor and materials	$227,000	(DC) X	3.0%	
Total fixed annual costs	$227,000			
Variable annual costs				
N/A	$0	Similar annual costs as current LNB		
Total variable annual costs	$0			
Total direct annual costs (DAC)	$227,000			
Indirect Annual Costs				
Cost for capital recovery	$984,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$984,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$1,211,000**			

Technology: Upgraded LNB with existing OFA System operation **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis	
CAPITAL COST			
Direct Costs			
Purchased equipment costs			
New coal elbow, nozzle with air vane, fuel injector barrel, air zone swirler and coal piping	$2,753,000	from vendor quote, 06/30/06	
Dynamic classifier for coal pulverizers	$1,760,000	B&V cost estimate	
Coal/air flow instrument for burners	$935,000	B&V cost estimate	
Neural network system for NOx optimization	$345,000	B&V cost estimate	
NOx monitoring equipment	$182,000	B&V cost estimate	
Water cannon system	$1,452,000	B&V cost estimate	
Subtotal capital cost (CC)	$7,427,000		
Freight	$371,000	(CC) X 5.0%	
Total purchased equipment cost (PEC)	$7,798,000	A1 + A2	
Direct installation costs			
Foundation & supports	$0	(PEC) X 0.0%	
Handling & erection	$1,560,000	(PEC) X 20.0%	
Electrical	$780,000	(PEC) X 10.0%	
Piping	$0	(PEC) X 0.0%	
Insulation	$0	(PEC) X 0.0%	
Painting	$0	(PEC) X 0.0%	
Demolition	$195,000	(PEC) X 2.5%	
Relocation	$0	(PEC) X 0.0%	
Total direct installation costs (DIC)	$2,535,000	B1 + B2	
Site preparation	$0	N/A	
Buildings	$0	N/A	
Total direct costs (DC) = (PEC) + (DIC)	$10,333,000		
Indirect Costs			
Engineering	$1,240,000	(DC) X 12.0%	
Owner's cost	$207,000	(DC) X 2.0%	
Construction management	$517,000	(DC) X 5.0%	
Start-up and spare parts	$207,000	(DC) X 2.0%	
Performance test	$50,000	Engineering estimate	
Contingencies	$1,033,000	(DC) X 10.0%	
Total indirect costs (IC)	$3,254,000		
Allowance for Funds Used During Construction (AFDC)	$611,000	[(DC)+(IC)] 8.99%	1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$14,198,000**		
ANNUAL COST			
Direct Annual Costs			
Fixed annual costs			
Maintenance labor and materials	$310,000	(DC) X 3.0%	
Total fixed annual costs	$310,000		
Variable annual costs			
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh	
Total variable annual costs	$540,000		
Total direct annual costs (DAC)	$850,000		
Indirect Annual Costs			
Cost for capital recovery	$1,340,000	(TCI) X 9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$1,340,000		
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$2,190,000**		

Technology: New Low NOx Burners & Modified OFA System **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis	
CAPITAL COST			
Direct Costs			
Purchased equipment costs			
New Low NOx Burners with new secondary air registers	$4,593,000	from vendor quote, 06/30/06	
(8) OFA ports and (4) wing ports with tube throat openings	$1,994,000	from vendor quote, 06/30/06	
Neural network system for NOx optimization	$346,000	B&V cost estimate	
NOx monitoring equipment	$182,000	B&V cost estimate	
Water cannon system	$1,452,000	B&V cost estimate	
Dynamic classifier for coal pulverizers	$1,760,000	B&V cost estimate	
Coal/air flow instrument for burners	$935,000	B&V cost estimate	
Modulating orifice for burners	$282,000	B&V cost estimate	
Subtotal capital cost (CC)	$11,544,000		
Freight	$577,000	(CC) X 5.0%	
Total purchased equipment cost (PEC)	$12,121,000		
Direct installation costs			
Foundation & supports	$0	(PEC) X 0.0%	
Handling & erection	$6,061,000	(PEC) X 50.0%	
Electrical	$1,212,000	(PEC) X 10.0%	
Piping	$606,000	(PEC) X 5.0%	
Insulation	$0	(PEC) X 0.0%	
Painting	$0	(PEC) X 0.0%	
Demolition	$606,000	(PEC) X 5.0%	
Relocation	$606,000	(PEC) X 5.0%	
Total direct installation costs (DIC)	$9,091,000		
Site preparation	$0	N/A	
Buildings	$0	N/A	
Total direct costs (DC) = (PEC) + (DIC)	$21,212,000		
Indirect Costs			
Engineering	$2,545,000	(DC) X 12.0%	
Owner's cost	$424,000	(DC) X 2.0%	
Construction management	$1,061,000	(DC) X 5.0%	
Start-up and spare parts	$424,000	(DC) X 2.0%	
Performance test	$50,000	Engineering estimate	
Contingencies	$4,242,000	(DC) X 20.0%	
Total indirect costs (IC)	$8,746,000		
Allowance for Funds Used During Construction (AFDC)	$2,693,000	[(DC)+(IC)] 8.99%	2 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$32,651,000**		
ANNUAL COST			
Direct Annual Costs			
Fixed annual costs			
Maintenance labor and materials	$636,000	(DC) X 3.0%	
Total fixed annual costs	$636,000		
Variable annual costs			
N/A	$0	No associated annual cost	
Total variable annual costs	$0		
Total direct annual costs (DAC)	$636,000		
Indirect Annual Costs			
Cost for capital recovery	$3,082,000	(TCI) X 9.44%	CRF at 7% interest & 20 year life
Total indirect annual costs (IDAC)	$3,082,000		
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$3,718,000**		

Technology: Selective Non-Catalytic Reduction **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Reagent storage, handling, injection & controls	$5,083,000	CUECost estimate			
Initial urea inventory	$255,000	150,000 gal. urea initial inventory			
Air preheater modifications	$2,835,000	CUECost estimate			
Subtotal capital cost (CC)	$8,173,000				
Freight	$490,380	(CC) X	6.0%		
Total purchased equipment cost (PEC)	$8,663,000				
Direct installation costs					
Foundation & supports	$433,000	(PEC) X	5.0%		
Handling & erection	$866,000	(PEC) X	10.0%		
Electrical	$866,000	(PEC) X	10.0%		
Piping	$260,000	(PEC) X	3.0%		
Insulation	$0	(PEC) X	0.0%		
Painting	$0	(PEC) X	0.0%		
Demolition	$173,000	(PEC) X	2.0%		
Relocation	$173,000	(PEC) X	2.0%		
Total direct installation costs (DIC)	$2,771,000				
Site preparation	$0	N/A			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$11,434,000				
Indirect Costs					
Engineering	$1,372,000	(DC) X	12.0%		
Owner's cost	$572,000	(DC) X	5.0%		
Construction management	$1,143,000	(DC) X	10.0%		
Start-up and spare parts	$343,000	(DC) X	3.0%		
Performance test	$100,000	Engineering estimate			
Contingencies	$1,715,000	(DC) X	15.0%		
Total indirect costs (IC)	$5,245,000				
Allowance for Funds Used During Construction (AFDC)	$750,000	[(DC)+(IC)]	8.99%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$17,429,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$100,000	1 FTE and		100,000 $/year	Estimated manpower
Maintenance labor and materials	$343,000	(DC) X	3.0%		
Total fixed annual costs	$443,000				
Variable annual costs					
Reagent	$3,093,000	2,637 lb/hr and		315 $/ton	Engineering estimate
Auxiliary and ID fan power	$26,000	70 kW and		0.05 $/kWh	Engineering estimate
Water	$179,000	200 gpm and		2 $/1,000 gal	Engineering estimate
Total variable annual costs	$3,298,000				
Total direct annual costs (DAC)	$3,741,000				
Indirect Annual Costs					
Cost for capital recovery	$1,645,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$1,645,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$5,386,000**				

Technology: New Low NOx Burners & Modified OFA System & SNCR **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Total Capital Investment (TCI) cost for:						
New Low NOx Burners & Modified OFA System	$32,651,000	Cost estimate for independent system				
Selective Non-Catalytic Reduction System	$17,429,000	Cost estimate for independent system				
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$50,080,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$100,000		1 FTE and	100,000 $/year		Estimated manpower
Maintenance labor and materials	$979,000	(DC) X	3.0%			
Total fixed annual costs	$1,079,000					
Variable annual costs						
Reagent	$1,105,000		942 lb/hr and	315 $/ton		Engineering estimate
Auxiliary and ID fan power	$26,000		70 kW and	0.05 $/kWh		Engineering estimate
Water	$179,000		200 gpm and	2 $/1,000 gal		Engineering estimate
Total variable annual costs	$1,310,000					
Total direct annual costs (DAC)	$2,389,000					
Indirect Annual Costs						
Cost for capital recovery	$4,728,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life		
Total indirect annual costs (IDAC)	$4,728,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$7,117,000**					

Technology: Upgraded Low NOx Burners with existing OFA and SNCR **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Total Capital Investment (TCI) cost for:						
Upgraded Low NOx Burners with existing OFA System	$14,198,000	Cost estimate for independent system				
Selective Non-Catalytic Reduction System	$17,429,000	Cost estimate for independent system				
Total Capital Investment (TCI) =	**$31,627,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$100,000		1	FTE and	100,000 $/year	Estimated manpower
Maintenance materials and labor	$653,000	(DC) X	3.0%			
Total fixed annual costs	$753,000					
Variable annual costs						
Replacement power due to efficiency hit	$540,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh				
Reagent	$2,430,000		2,072	lb/hr and	315 $/ton	Engineering estimate
Auxiliary power	$26,000		70	kW and	0.05 $/kWh	Engineering estimate
Water	$179,000		200	gpm and	2 $/1,000 gal	Engineering estimate
Total variable annual costs	$3,175,000					
Total direct annual costs (DAC)	$3,928,000					
Indirect Annual Costs						
Cost for capital recovery	$2,986,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life		
Total indirect annual costs (IDAC)	$2,986,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$6,914,000**					

Technology: New Low NOx Burners & Modified OFA System & SCR **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis		
CAPITAL COST				
Direct Costs				
Purchased equipment costs				
Reactor housing	$5,580,000	CUECost estimate		
Ammonia handling and injection	$2,589,000	CUECost estimate		
Initial catalyst and ammonia	$4,750,000	CUECost estimate		
Electrical system modification	$2,261,000	from ref. cost		
ID fans	$3,658,000	from ref. cost		
Flue gas handling system	$6,500,000	from ref. cost		
Air preheater modifications	$2,835,000	CUECost estimate		
Ash handling system	$3,110,000	CUECost estimate		
Subtotal capital cost (CC)	$31,283,000			
Instruments and controls	$3,128,000	(CC) X 10.0%		
Freight	$1,564,000	(CC) X 5.0%		
Total purchased equipment cost (PEC)	$35,975,000			
Direct installation costs				
Foundation & supports	$13,671,000	(PEC) X 38.0%		
Handling & erection	$13,311,000	(PEC) X 37.0%		
Electrical	$8,994,000	(PEC) X 25.0%		
Piping	$2,698,000	(PEC) X 7.5%		
Insulation	$3,598,000	(PEC) X 10.0%		
Painting	$360,000	(PEC) X 1.0%		
Demolition	$6,116,000	(PEC) X 17.0%		
Relocation	$4,317,000	(PEC) X 12.0%		
Total direct installation costs (DIC)	$53,065,000			
Site preparation	$2,000,000	Engineering estimate		
Buildings	$500,000	Engineering estimate		
Total direct costs (DC) = (PEC) + (DIC)	$91,540,000			
Indirect Costs				
Engineering	$10,985,000	(DC) X 12.0%		
Owner's cost	$4,577,000	(DC) X 5.0%		
Construction management	$9,154,000	(DC) X 10.0%		
Start-up and spare parts	$2,746,000	(DC) X 3.0%		
Performance test	$200,000	Engineering estimate		
Contingencies	$13,731,000	(DC) X 15.0%		
Total indirect costs (IC)	$41,393,000			
Allowance for Funds Used During Construction (AFDC)	$17,926,000	[(DC)+(IC)] 8.99%	3 years (project time length X 1/2)	
Boiler Heat Transfer Surface Area Replacement	$40,000,000	B&V estimate to reduce SCR inlet FG temperature		
Total SCR Capital Investment (TCI)	**$190,859,000**			
Total Capital Investment (TCI) cost for:				
New Low NOx Burners & Modified OFA System	$32,651,000	Cost estimate for independent system		
Total Capital Investment (TCI) for LNB/OFA and SCR	**$223,510,000**			
ANNUAL COST				
Direct Annual Costs				
Fixed annual costs				
Operating labor	$100,000	1 FTE and	100,000 $/year	Estimated manpower
Maintenance labor & materials	$2,746,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering estimate		
Catalyst activity testing	$5,000	Engineering estimate		
Fly ash sampling and analysis	$20,000	Engineering estimate		
Total fixed annual costs	$2,896,000			
Variable annual costs				
Reagent	$797,000	475 lb/hr and	450 $/ton	Engineering estimate
Auxiliary and ID fan power	$944,000	2,537 kW and	0.05 $/kWh	Engineering estimate
Catalyst replacement	$1,035,000	173 m3 and	6,000 $/m3	3 yr replacement rate
Catalyst disposal	$1,000	292,483 lb and	10 $/ton	3 yr replacement rate
Total variable annual costs	$2,777,000			
Total direct annual costs (DAC)	$5,673,000			
Indirect Annual Costs				
Cost for capital recovery	$21,099,000	(TCI) X 9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$21,099,000			
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$26,772,000**			

Technology: *Wet Flue Gas Desulfurization (FGD)* **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Reagent feed system: receiving, storage	$1,417,000	CUECost estimate			
Ball mill & classifier	$2,154,000	CUECost estimate			
SO2 removal system: tanks, pumps	$3,855,000	CUECost estimate			
Absorber tower	$30,207,000	CUECost estimate			
Spray pumps	$4,517,000	CUECost estimate			
Byproduct handling system	$1,737,000	CUECost estimate			
Vacuum filter system	$1,650,000	from ref. cost			
Fabric filter with ash handling system	$16,526,000	from ref. cost			
Booster fans	$4,840,000	Engineering estimate			
Electrical system upgrades	$4,245,491	from ref. cost			
Flue gas handling system	$8,800,000	Engineering estimate			
Subtotal capital cost (CC)	$79,948,491				
Instrumentation and controls	$3,997,000	(CC) X 5.0%			
Freight	$3,997,000	(CC) X 5.0%			
Total purchased equipment cost (PEC)	$87,942,000				
Direct installation costs					
Foundation & supports	$24,184,000	(PEC) X 27.5%			
Handling & erection	$35,177,000	(PEC) X 40.0%			
Electrical	$17,588,000	(PEC) X 20.0%			
Piping	$4,397,000	(PEC) X 5.0%			
Insulation	$4,397,000	(PEC) X 5.0%			
Painting	$879,000	(PEC) X 1.0%			
Demolition	$3,518,000	(PEC) X 4.00%			
Relocation	$3,518,000	(PEC) X 4.00%			
Total direct installation costs (DIC)	$93,658,000				
Site preparation	$200,000	Engineering estimate			
Buildings	*$7,500,000*	*Engineering estimate*			
New wet stack	$23,000,000	Recent quotes estimate of $23 mil			
Waste water treatment system	$15,000,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$227,300,000				
Indirect Costs					
Engineering	$27,276,000	(DC) X 12.0%			
Owner's cost	$9,092,000	(DC) X 4.0%			
Construction management	$22,730,000	(DC) X 10.0%			
Start-up and spare parts	*$3,410,000*	*(DC) X 1.5%*			
Performance test	$200,000	Engineering estimate			
Contingencies	$34,095,000	(DC) X 15.0%			
Total indirect costs (IC)	$96,803,000				
Allowance for Funds Used During Construction (AFDC)	$58,274,000	[(DC)+(IC)] 8.99%		4 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$382,377,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Operating labor	$400,000		4 FTE and	100,000 $/year	Estimated manpower
Maintenance labor and materials	$6,819,000	(DC) X 3.0%			
Total fixed annual costs	$7,219,000				
Variable annual costs					
Reagent	$2,015,000		5.9 tph and	46 $/ton	Mass bal. calcs.
Byproduct disposal	$806,000		10.8 tph and	10 $/ton	Mass bal. calcs.
Auxiliary and ID fan power	$5,679,000		15,254 kW and	0.05 $/kWh	CueCost calculations
Water	$532,000		595 gpm and	2 $/1,000 gal	Mass bal. calcs.
Bag replacement cost	$632,000		6,322 bags and	100 $/bag	18,966 total bags
Cage replacement cost	$158,000		3,161 cages and	50 $/cage	18,966 total cages
Total variable annual costs	$8,500,000				
Total direct annual costs (DAC)	$15,719,000				
Indirect Annual Costs					
Cost for capital recovery	$36,096,000	(TCI) X 9.44%		CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$36,096,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$51,815,000**				

Technology: Semi-Dry Flue Gas Desulfurization (FGD) **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Reagent feed: receiving, storage, grinding	$3,337,000	CUECost estimate				
SO2 removal system: tanks, pumps	$3,164,000	CUECost estimate				
Spray dryers and fabric filter	$41,189,000	CUECost estimate				
Ash handling system	$2,000,000	from ref. cost				
Booster fans	$4,840,000	Engineering estimate				
Electrical system upgrades	$2,860,000	from ref. cost				
Flue gas handling system	$8,800,000	CUECost estimate				
Subtotal capital cost (CC)	$66,190,000					
Instrumentation and controls	$1,324,000	(CC) X	2.0%			
Freight	$3,310,000	(CC) X	5.0%			
Total purchased equipment cost (PEC)	$70,824,000					
Direct installation costs						
Foundation & supports	$19,477,000	(PEC) X	27.5%			
Handling & erection	$28,330,000	(PEC) X	40.0%			
Electrical	$14,165,000	(PEC) X	20.0%			
Piping	$3,541,000	(PEC) X	5.0%			
Insulation	$3,541,000	(PEC) X	5.0%			
Painting	$708,000	(PEC) X	1.0%			
Demolition	$2,833,000	(PEC) X	4.0%			
Relocation	$2,833,000	(PEC) X	4.0%			
Total direct installation costs (DIC)	$75,428,000					
Site preparation	$200,000	Engineering estimate				
Buildings	$500,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$146,952,000					
Indirect Costs						
Engineering	$17,634,000	(DC) X	12.0%			
Owner's cost	$5,878,000	(DC) X	4.0%			
Construction management	$14,695,000	(DC) X	10.0%			
Start-up and spare parts	$2,204,000	(DC) X	1.5%			
Performance test	$200,000	Engineering estimate				
Contingencies	$22,043,000	(DC) X	15.0%			
Total indirect costs (IC)	$62,654,000					
Allowance for Funds Used During Construction (AFDC)	$37,687,000	[(DC)+(IC)] X	8.99%	4 years (project time length X 1/2)		
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$247,293,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Operating labor	$300,000		3 FTE and	100,000 $/year		Estimated manpower
Maintenance labor and materials	$4,409,000	(DC) X	3.0%			
Total fixed annual costs	$4,709,000					
Variable annual costs						
Reagent	$4,915,000		5.0 tph and	132 $/ton		Mass bal. calcs.
Byproduct disposal	$742,000		10.0 tph and	10 $/ton		Mass bal. calcs.
Bag replacement cost	$632,000		6,322 bags and	100 $/bag		18,966 total bags
Cage replacement cost	$158,000		3,161 cages and	50 $/cage		18,966 total bags
Auxiliary and ID fan power	$1,522,000		4,088 kW and	0.05 $/kWh		CueCost calculations
Water	$300,000		336 gpm and	2 $/1,000 gal		Mass bal. calcs.
Total variable annual costs	$8,269,000					
Total direct annual costs (DAC)	$12,978,000					
Indirect Annual Costs						
Cost for capital recovery	$23,344,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life		
Total indirect annual costs (IDAC)	$23,344,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$36,322,000**					

Technology: Pulse Jet Fabric Filter (PJFF) **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Fabric filter system	$16,968,000	CUECost estimate				
Initial FF bags inventory	included					
Ash handling system	$1,210,000	Engineering estimate				
Booster fans	$5,434,000	Engineering estimate				
Electrical system upgrades	$2,057,000	from ref. cost				
Flue gas handling system	$3,630,000	Engineering estimate				
Subtotal capital cost (CC)	$29,299,000					
Instrumentation and controls	$1,465,000	(CC) X	5.0%			
Freight	$1,465,000	(CC) X	5.0%			
Total purchased equipment cost (PEC)	$32,229,000					
Direct installation costs						
Foundation & supports	$9,669,000	(PEC) X	30.0%			
Handling & erection	$9,669,000	(PEC) X	30.0%			
Electrical	$4,834,000	(PEC) X	15.0%			
Piping	$806,000	(PEC) X	2.5%			
Insulation	$645,000	(PEC) X	2.0%			
Painting	$322,000	(PEC) X	1.0%			
Demolition	$1,611,000	(PEC) X	5.00%			
Relocation	$322,000	(PEC) X	1.00%			
Total direct installation costs (DIC)	$27,878,000					
Site preparation	$150,000	Engineering estimate				
Buildings	$0	N/A				
Total direct costs (DC) = (PEC) + (DIC)	$60,257,000					
Indirect Costs						
Engineering	$7,231,000	(DC) X	12.0%			
Owner's cost	$3,013,000	(DC) X	5.0%			
Construction management	$6,026,000	(DC) X	10.0%			
Start-up and spare parts	$904,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$9,039,000	(DC) X	15.0%			
Total indirect costs (IC)	$26,313,000					
Allowance for Funds Used During Construction (AFDC)	$7,783,000	[(DC)+(IC)]	8.99%		2 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$94,353,000**					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$1,808,000	(DC) X	3.0%			
Total fixed annual costs	$1,808,000					
Variable annual costs						
Bag replacement cost	$632,000	6,322	bags and	100	$/bag	18,966 total bags
Cage replacement cost	$158,000	3,161	cages and	50	$/cage	18,966 total cages
ID fan power	$1,121,000	3,011	kW and	0.05	$/kWh	8" water d.p.
Auxiliary power	$210,000	563	kW and	0.05	$/kWh	Engineering estimate
Total variable annual costs	$2,121,000					
Total direct annual costs (DAC)	$3,929,000					
Indirect Annual Costs						
Cost for capital recovery	$8,907,000	(TCI) X	9.44%		CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$8,907,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$12,836,000**					

Technology: Compact Hybrid Particulate Collector (COHPAC) **Date:** 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Fabric filter system	$12,183,000	from ref. cost			
Initial FF bags inventory	included				
Ash handling system	$2,200,000	from ref. cost			
Booster fans	$5,016,000	Engineering estimate			
Electrical system upgrades	$2,057,000	from ref. cost			
Flue gas handling system	$6,600,000	Engineering estimate			
Subtotal capital cost (CC)	$28,056,000				
Instrumentation and controls	$1,403,000	(CC) X 5.0%			
Freight	$1,403,000	(CC) X 5.0%			
Total purchased equipment cost (PEC)	$30,862,000				
Direct installation costs					
Foundation & supports	$7,716,000	(PEC) X 25.0%			
Handling & erection	$7,716,000	(PEC) X 25.0%			
Electrical	$3,858,000	(PEC) X 12.5%			
Piping	$772,000	(PEC) X 2.5%			
Insulation	$617,000	(PEC) X 2.0%			
Painting	$309,000	(PEC) X 1.0%			
Demolition	$309,000	(PEC) X 1.00%			
Relocation	$309,000	(PEC) X 1.00%			
Total direct installation costs (DIC)	$21,606,000				
Site preparation	$500,000	Engineering estimate			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$52,968,000				
Indirect Costs					
Engineering	$6,356,000	(DC) X 12.0%			
Owner's cost	$2,648,000	(DC) X 5.0%			
Construction management	$5,297,000	(DC) X 10.0%			
Start-up and spare parts	$795,000	(DC) X 1.5%			
Performance test	$100,000	Engineering estimate			
Contingencies	$7,945,000	(DC) X 15.0%			
Total indirect costs (IC)	$23,141,000				
Allowance for Funds Used During Construction (AFDC)	$6,842,000	[(DC)+(IC)] 8.99%		2 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$82,951,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$1,589,000	(DC) X 3.0%			
Total fixed annual costs	$1,589,000				
Variable annual costs					
Filter bag replacement	$381,000	3,805 bags and	100 $/bag	11,415 total bags	
Cage replacement	$95,000	1,903 cages and	50 $/cage	11,415 total cages	
ID fan power	$807,000	2,167 kW and	0.05 $/kWh	6" water d.p.	
Auxiliary power	$204,000	549 kW and	0.05 $/kWh	Engineering estimate	
Total variable annual costs	$1,487,000				
Total direct annual costs (DAC)	$3,076,000				
Indirect Annual Costs					
Cost for capital recovery	$7,831,000	(TCI) X 9.44%	CRF at 7% interest & 20 year life		
Total indirect annual costs (IDAC)	$7,831,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$10,907,000**				

Technology: Wet ESP

Date: 10/11/2007

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
WESP system includes casing, electrical sys., penthouse blower & heater, access provisions	$31,242,000	from ref. cost			
Ash handling system	$2,420,000	from ref. cost			
Booster fans	$4,598,000	Engineering estimate			
Electrical system upgrades	$1,331,000	from ref. cost			
Flue gas handling system	$3,630,000	Engineering estimate			
Subtotal capital cost (CC)	$43,221,000				
Instrumentation and controls	$2,161,000	(CC) X	5.0%		
Freight	$2,161,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$47,543,000				
Direct installation costs					
Foundation & supports	$14,263,000	(PEC) X	30.0%		
Handling & erection	$14,263,000	(PEC) X	30.0%		
Electrical	$7,131,000	(PEC) X	15.0%		
Piping	$1,189,000	(PEC) X	2.5%		
Insulation	$951,000	(PEC) X	2.0%		
Painting	$475,000	(PEC) X	1.0%		
Demolition	$475,000	(PEC) X	1.00%		
Relocation	$475,000	(PEC) X	1.00%		
Total direct installation costs (DIC)	$39,222,000				
Site preparation	$500,000	Engineering estimate			
Buildings	$0	N/A			
New wet stack	$23,000,000	Recent quotes estimate of $23 mil			
Total direct costs (DC) = (PEC) + (DIC)	$110,265,000				
Indirect Costs					
Engineering	$13,232,000	(DC) X	12.0%		
Owner's cost	$5,513,000	(DC) X	5.0%		
Construction management	$11,027,000	(DC) X	10.0%		
Start-up and spare parts	$1,309,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$16,540,000	(DC) X	15.0%		
Total indirect costs (IC)	$47,721,000				
Allowance for Funds Used During Construction (AFDC)	$21,304,000	[(DC)+(IC)]	8.99%	3 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	**$179,290,000**				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance materials and labor	$2,618,000	(DC) X	3.0%		
Operating labor	$100,000	1 FTE and		100000 $/year	Estimated manpower
Total fixed annual costs	$2,718,000				
Variable annual costs					
Reagent	$179,000	20 lb/hr and		1.20 $/ton	Engineering estimate
Auxiliary power	$130,000	350 kW and		0.05 $/kWh	Engineering estimate
ID fan power	$522,000	1,402 kW and		0.05 $/kWh	4" water d.p.
Service water	$583,000	652 gpm and		2 $/1,000 gal	Engineering estimate
Total variable annual costs	$1,414,000				
Total direct annual costs (DAC)	$4,132,000				
Indirect Annual Costs					
Cost for capital recovery	$16,925,000	(TCI) X	9.44%	CRF at 7% interest & 20 year life	
Total indirect annual costs (IDAC)	$16,925,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$21,057,000**				

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Cowlitz Falls Hydro Resource - Projected Costs FY 2010-2015

Initial Rate Proposal Consistent with IPR Closeout and Program Case Rates[1]

Purchase Power Contract

Cowlitz Falls Hydro Project Resource - Cost Projections for FY 2010[1]

7(b)(2) Case - Resource Stack Values:	FY 2010-$$	FY 2015-$$
Total Operation and Maintenance - 6-year average FY 2010 - FY 2015 as Adjusted	$3,597,673	3,979,364
Debt Service - 6-year average FY 2010 - FY 2015 - Note 3	11,620,481	11,620,481
Total Combined Costs - O&M and Debt Service	15,218,153	15,599,845
Cost per MWh	$66.82	$68.49
Capital Investment	194,980,245	194,980,245
Estimated remaining useful life = 60 years	60 years	60 years
Placed in service	1994	1994
Average Annual Energy Output/@ 26.0MWh[3]	227,760	227,760

Projected Budget Amounts - IPR-1 - Program Case Revenue Requirement Amounts:

	FY2010	FY2011	FY2012	FY2013	FY2014	FY2015
Program Case Revenue Requirement:						
Operation and Maintenance Charges	2,787,500	2,818,800	2,847,500	2,875,500	2,903,500	2,932,535
Transmission Charges	897,000	897,000	940,000	940,000	940,000	940,000
Debt Service Payments 4.20% Actual	11,566,000	11,563,000	11,559,000	11,546,000	11,542,000	11,530,806
Total Amounts Paid - Program Case Rates	15,250,500	15,278,800	15,346,500	15,361,500	15,385,500	15,403,341
7(b)(2) Case Revenue Requirement Amounts:						
Annual Operation and Maintenance Charges	2,787,500	2,818,800	2,847,500	2,875,500	2,903,500	2,932,535
Annual Transmission Charges	897,000	897,000	940,000	940,000	940,000	940,000
Total Annual O&M	3,684,500	3,715,800	3,787,500	3,815,500	3,843,500	3,872,535
O&M Adjustment - Note 2	(86,827)	(45,339)	(40,229)	8,063	57,503	106,829
Adjusted Annual O&M	3,597,673	3,670,461	3,747,271	3,823,563	3,901,003	3,979,364
Debt Service Payments @ 4.25% - Note 3	11,620,481	11,620,481	11,620,481	11,620,481	11,620,481	11,620,481
Total Amounts Paid - 7(b)(2) Case Rates, assuming resource selection FY 2010.	15,218,153	15,290,941	15,367,752	15,444,044	15,521,484	15,599,845
Average Annual Energy Output/@ 26.0MWh[4]	227,760	227,760	227,760	227,760	227,760	227,760
Cost per MWh	$66.82	$67.14	$67.47	$67.81	$68.15	$68.49

Notes:

Note 1 - Upon additional review, it was discovered that the projected costs that were used to forecast the costs of purchased power under this contract that are outlined in the schedule above need to be revised upward. The cost presented above for this resource that are contained in the 7(b)(2) resource stack are consistent with the costs for this resource that are contained in the Program Case for the Initial Rate Proposal. The decision was made to not change the purchased power amounts so that BPA's Initial Rate Proposal was consistent with the information contained in the Integrated Program Review (IPR) documentation that was finalized in a letter sent by David J. Armstrong, Executive Vice President and Chief Financial Officer to BPA's Customers and other interested parties on November 14, 2008. The correct contract price amounts and the corrected purchase power cost for this contract can be found at pages 3 and 4. Unless there are additional changes that become known between the Initial Rate Proposal and the Final Rate Proposal, the revised amounts on pages 3 and 4 will be used for the final rate proposal. The total annual purchase power cost above of $15,250,500 (Program Case) for FY 2010 is understated by $460,009, the projected revised amount that is displayed on page 3 of 4 is $15,710,509 (Program Case).

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Cowlitz Falls Hydro Resource - Projected Costs FY 2010-2015

Initial Rate Proposal Consistent with IPR Closeout and Program Case Rates[1]

Purchase Power Contract

<u>Note 2</u> - Due to model escalation of O&M, the average projected annual cost for O&M and Transmission costs of $3,599,788 for FY2010-2015 stated in real 2010 dollars in the Program Case amount was decreased by ($ 2,155), so that the average annual escalated rate during the rate test period was equal to the average Program Case rate. This adjustment is necessary to ensure that these costs are similar between the Program Case and the 7(b)(2) Case. This adjustment results in the sum of O&M and Transmission Costs for FY 2010 being decreased by ($ 86,827). The FY 2010 amount of $3,597,673 is then escalated in the rates model using the Cumulative GDP Inflator /Deflator values that are reflected in the table below.

	Total Annual O&M Before Adjustment	GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Program Case Nominal $$	7(b)(2) Case Escalated Cost Projections	7(b)(2) Case Over /(Under) Program Case
FY2010	3,684,500	1.000000	3,684,500	3,684,500	3,597,673	(86,827)
FY2011	3,715,800	1.020232	3,642,113	3,715,800	3,670,461	(45,339)
FY2012	3,787,500	1.041582	3,636,296	3,787,500	3,747,271	(40,229)
FY2013	3,815,500	1.062788	3,590,086	3,815,500	3,823,563	8,063
FY2014	3,843,500	1.084313	3,544,641	3,843,500	3,901,003	57,503
FY2015	3,872,535	1.106094	3,501,090	3,872,535	3,979,364	106,829
Averages	3,786,556		3,599,788		Total Differences	(1)
		Program Case Price Adjustment	(2,115)			
		7(b)(2) Case Pricing - 2010 $$	3,597,673			

<u>Note 3</u> - Calculation of 7(b)(2) Debt Service - Average annual program case debt service FY2010-2015 = 11,551,134 Program Case Debt Service. Assuming 30 yr term financing at interest rate of 4.20% in the program case, the PV of the payment stream of 30 annual payments at an interest rate of 4.20% = Principle Amount Financed FY 2010 = 194,980,245 . In the 7(b)(2) Case, the debt service payments associated with retiring a principle amount of annual debt service payments for a principle amount of $195,148,632, @ 4.25% = 11,620,481 This amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model to minimize the models escalation of fixed amounts of debt service.

<u>Note 4</u> - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA, 2007 Pacific Northwest Loads and Resources Study on page 23.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Cowlitz Falls Hydro Resource - Projected Costs FY 2010-2015

Draft - Updated Proposed Cost Projections for Final Rate Proposal

Purchase Power Contract

Cowlitz Falls Hydro Project Resource - Cost Projections for FY 2010

7(b)(2) Case - Resource Stack Values:	**FY 2010-$$**	**FY 2015-$$**
Total Operation and Maintenance - 6-year average FY 2010 - FY 2015 as Adjusted	$4,134,918	4,573,608
Debt Service - 6-year average FY 2010 - FY 2015	11,620,481	11,620,481
Total Combined Costs - O&M and Debt Service	15,755,398	16,194,088
Cost per MWh	$69.18	$71.10
Capital Investment	194,980,245	194,980,245
Estimated remaining useful life = 60 years	60 years	60 years
Placed in service	1994	1994
Average Annual Energy Output/@ 26.0MWh[3]	227,760	227,760

Projected Budget Amounts - IPR-2 - Program Case Revenue Requirement Amounts:

	FY2010	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**
Program Case Revenue Requirement:						
Operation and Maintenance Charges	3,273,954	3,236,807	3,405,122	3,522,965	3,610,969	3,738,898
Transmission Charges	870,555	870,555	890,555	890,555	890,555	910,555
Debt Service Payments 4.20% Actual	11,566,000	11,563,000	11,559,000	11,546,000	11,542,000	11,530,806
Total Amounts Paid - Program Case Rates	15,710,509	15,670,362	15,854,677	15,959,520	16,043,524	16,180,259
7(b)(2) Case Revenue Requirement Amounts:						
Annual Operation and Maintenance Charges	3,273,954	3,236,807	3,405,122	3,522,965	3,610,969	3,738,898
Annual Transmission Charges	870,555	870,555	890,555	890,555	890,555	910,555
Total Annual O&M	4,144,509	4,107,362	4,295,677	4,413,520	4,501,524	4,649,453
O&M Adjustment - Note 1	(9,591)	111,213	11,179	(18,979)	(17,979)	(75,845)
Adjusted Annual O&M	4,134,918	4,218,575	4,306,856	4,394,541	4,483,545	4,573,608
Debt Service Payments @ 4.25% - Note 2	11,620,481	11,620,481	11,620,481	11,620,481	11,620,481	11,620,481
Total Amounts Paid - 7(b)(2) Case Rates, assuming resource selection FY 2010.	15,755,398	15,839,056	15,927,337	16,015,022	16,104,026	16,194,088
Average Annual Energy Output/@ 26.0MWh[3]	227,760	227,760	227,760	227,760	227,760	227,760
Cost per MWh	$69.18	$69.54	$69.93	$70.32	$70.71	$71.10

Notes:

Note 1 - Due to model escalation of O&M, the average projected annual cost for O&M and Transmission costs of $4,133,728 for FY2010-2015 stated in real 2010 dollars in the Program Case amount was increased by $ 1,190, so that the average annual escalated costs during the rate test period were equal to the average Program Case costs. This adjustment is necessary to ensure that these costs are similar between the Program Case and the 7(b)(2) Case. This adjustment results in the sum of O&M and Transmission Costs for FY 2010 being decreased by ($ 9,591). The FY 2010 adjusted amount of $4,134,918 is then escalated in the rates model using the Cumulative GDP Inflator /Deflator values that are reflected in the table below.

WP-10 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Cowlitz Falls Hydro Resource - Projected Costs FY 2010-2015

Draft - Updated Proposed Cost Projections for Final Rate Proposal

Purchase Power Contract

Note 1 - continued

	Total Annual O&M Before Adjustment	GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Program Case Nominal $$	7(b)(2) Case Escalated Cost Projections	7(b)(2) Case Over /(Under) Program Case
FY2010	4,144,509	1.000000	4,144,509	4,144,509	4,134,918	(9,591)
FY2011	4,107,362	1.020232	4,025,910	4,107,362	4,218,575	111,213
FY2012	4,295,677	1.041582	4,124,185	4,295,677	4,306,856	11,179
FY2013	4,413,520	1.062788	4,152,776	4,413,520	4,394,541	(18,979)
FY2014	4,501,524	1.084313	4,151,499	4,501,524	4,483,545	(17,979)
FY2015	4,649,453	1.106094	4,203,488	4,649,453	4,573,608	(75,845)
Averages	4,352,008		4,133,728		Total Differences	(2)
	Program Case Price Adjustment		1,190			
	7(b)(2) Case Pricing - 2010 $$		4,134,918			

Note 2 - Calculation of 7(b)(2) Debt Service - Average annual program case debt service FY2010-2015 = 11,551,134 Program Case Debt Service. Assuming 30 yr term financing at interest rate of 4.20% in the program case, the PV of the payment stream of 30 annual payments at an interest rate of 4.20% = Principle Amount Financed FY 2010 = 194,980,245 . In the 7(b)(2) Case, the debt service payments associated with retiring a principle amount of annual debt service payments for a principle amount of $195,148,632, @ 4.25% = 11,620,481 This amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model to minimize the models escalation of fixed amounts of debt service.

Note 3 - Firm average energy value (aMW) was obtained from Table 5 of the March 2007 BPA, 2007 Pacific Northwest Loads and Resources Study on page 23.

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Cowlitz Falls Hydro Project Resource for FY 2010-2015
Purchase Power Contract

Cowlitz Falls Power Purchase Contract - Projected Cost Comparisons
Initial Rate Proposal and Projected Final Rate Proposal Amounts

Current IPR 1 - Program Case Amounts - Initial Rate Proposal:

	Annual Energy Purchased MWh	Annual Purchased Power Cost	Other Costs	Total Cost
FY2010	227,760	$15,250,500	$0	$15,250,500
FY2011	227,760	$15,278,800	$0	$15,278,800
FY2012	227,760	$15,346,500	$0	$15,346,500
FY2013	227,760	$15,361,500	$0	$15,361,500
FY2014	227,760	$15,385,500	$0	$15,385,500
FY2015	227,760	$15,403,341	$0	$15,403,341

(A) - 7(b)(2) Case Initial Proposal - Adjusted FY 2010 Power Purchase Cost Amount = $15,218,153

Preliminary Projected IPR-2 - Program Case Amount - Final Rate Proposal

	Annual Energy Purchased MWh	Annual Purchased Power Cost	Other Costs	Total Cost	Increase In Annual Power Purchase Costs
FY2010	227,760	$15,710,509	$0	$15,710,509	$460,009
FY2011	227,760	$15,670,362	$0	$15,670,362	$391,562
FY2012	227,760	$15,854,677	$0	$15,854,677	$508,177
FY2013	227,760	$15,959,520	$0	$15,959,520	$598,020
FY2014	227,760	$16,043,524	$0	$16,043,524	$658,024
FY2015	227,760	$16,180,259	$0	$16,180,259	$776,918

(B) - 7(b)(2) Case Adjusted FY 2010 Projected Final Rate Case Power Purchase Cost Amount = $15,755,398

Preliminary Projected Increase in 7(b)(2) Case Adjusted FY 2010 Power
Purchase Cost Amount Between Initial Proposal Cost and Final Proposal Cost (B-A) = $537,245

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Idaho Falls Hydro Project Resource for FY 2010-2015
Purchase Power Contract

Initial Rate Proposal - IPR -1 Budget Projections November 2008:[1]

Idaho Falls Hydro Project Resource - Initial Rate Proposal Purchase Power Cost Projections:

	MWh	$/MWh	FY2010-$$	FY2015-$$
Annual Power Purchase Cost	162,060	$37.74	$6,115,376	$6,764,181
Placed in service			1982	1982
Projected Average Annual Energy Output[2]			162,060	162,060
Average Hourly Energy aMW			18.5	18.5
Cost per MWh			$37.74	$41.74
Estimated remaining useful life = 60 years			60 years	60 years

	Projected Contract Price[1, 3]	GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Projected Program Case Revenue Requirement Purchase Amounts Nominal $$	Projected Program Case Revenue Requirement Other Costs[4] Nominal $$	Total Program Case Revenue Requirement Nominal $$[1]	7(b)(2) Case Escalated Adjusted Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2010	$39.05	1.000000	39.05	6,328,443	108,000	6,436,443	6,115,376	(321,067)
FY 2011	$39.05	1.020232	38.28	6,328,443	108,000	6,436,443	6,239,102	(197,341)
FY 2012	$39.05	1.041582	37.49	6,328,443	108,000	6,436,443	6,369,666	(66,777)
FY 2013	$39.05	1.062788	36.74	6,328,443	108,000	6,436,443	6,499,348	62,905
FY 2014	$39.05	1.084313	36.01	6,328,443	108,000	6,436,443	6,630,982	194,539
FY 2015	$39.05	1.106094	35.30	6,328,443	108,000	6,436,443	6,764,181	327,738
Averages	$39.05		37.15			6,436,443	Total Difference	(4)
Program Case Price Adjustment - Note 5			(0.08)			(321,067)		
Adjusted 7(b)(2) Case Pricing - 2010$$5			37.74			6,115,376		

Projected Average Annual Energy Output[2] 162,060

Cost per MWh 37.74

Notes:

Note 1 - Projected Contract Pricing MWh - $39.05 at contract cap rate, cost of power is expected to be at the current contract cap during the remaining years of the current contract that expires on September 30, 2011. Only one month in FY 2007 and one month in FY 2008 was billed at a rate below the contract cap. The above projected costs of $6,436,443 is consistent with the Program Case Revenue Requirement and the Integrated Program Review (IPR) documentation that was finalized in a letter sent by David J. Armstrong, Executive Vice President and Chief Financial Officer to BPA's Customers and other interested parties on November 14, 2008.

Note 2 - The projected annual amount of energy purchased from the Idaho Falls Project for the Initial Proposal was based on the Loads and Resources Study which is consistent with the amounts displayed below that were contained in BPA's 2007 White Book. The average annual amount of production was projected at 162,060MWh - 1937 Water. This amount is expected to change for the Final Study to an annual amount of approximately 122,000 MWh based on the average annual production for FY 2002-2008, see the following preliminary projection of the quantity and cost for the Idaho Falls resource for Final Proposal on pages 3 and 4. Thus the amounts of power included in the Initial Proposal's projections are overstated and will be adjusted for the Final Rate Proposal.

Notes - continued:

Table A-4: Regional Independent Hydro Projects, PNW Loads and Resource Study, 2009 - 2010 Fiscal Years, [51] 2007 Final Supplemental Rate Case (Final), 1937 Water Year, 7/17/2008

Projected annual hydro production for Idaho Falls Resource = 18.5 aMW 8,760 = 162,060

2007 BPA White Book Resource Values Table 5, page 23

Date in Service	1982	Total Annual Energy @ 18	157,680
Capacity Peak MW	18	Total Annual Energy @ 19	166,440
Firm energy aMW	19	LARIS average @ 18.5 aMW	162,060

Note 3 - BPA is hopeful that a new power purchase contract with Idaho Falls Power will be negotiated before the time when final studies for the WP-10 Rate Case needs to be produced. The cost of power is expected to increase under the new contract and thus the cost of power for FY2012-2015 on a MWh basis per the Initial Proposal's cost projections are understated. See the following preliminary projection of the quantity and cost for the Idaho Falls resource for the Final Proposal on pages 3 and 4. The Final Rate Proposal pricing amounts will reflect the new power purchase contract amounts.

Note 4 - Any additional costs associated with the purchase and administration of this contract is already reflected in BPA's Program Case Revenue Requirement for salaries and general and administrative overhead amounts. Thus this cost amount which was incorrectly included in the IPR amounts and the Initial Proposal will be removed for the Final Rate Proposal.

Note 5 - Due to the rate model's escalation of O&M (escalation of the contract price amount by annual inflation), the average projected price amount (stated in 2010 $$$) of $6,436,443 that is applicable to the Program Case amount was decreased by ($321,1,067) to $6,115,376. This adjustment is necessary so that the average escalated rate during the rate test period is equal to the average Program Case annual cost. The FY 2010 amount of $6,115,376 is then escalated in the rates model using the Cumulative GDP Inflator /Deflator values that are reflected in the above table.

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Idaho Falls Hydro Project Resource for FY 2010-2015
Purchase Power Contract

IPR -2 Budget Projections March-April 2009 - Preliminary Final Rate Proposal Projections:

Idaho Falls Hydro Project Resource - Purchase Power Cost Projections:

	MWh	$/MWh	FY2010-$$	FY2015-$$
Annual Power Purchase Cost	121,747	$44.78	$5,451,346	6,029,702
Placed in service			1982	1982
Projected Average Annual Energy Output[3]			121,747	121,747
Average Hourly Energy aMW			13.9	13.9
Cost per MWh[1,2]			$44.78	$49.53
Estimated remaining useful life = 60 years			60 years	60 years

Projected Purchase Power Contract Pricing with Idaho Falls Power

	Projected Contract Price[1, 2]	GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Projected Program Case Revenue Requirement Purchase Amounts Nominal $$	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2010	$39.05	1.000000	39.05	4,754,237	5,451,346	697,109
FY 2011	$39.05	1.020232	38.28	4,754,237	5,561,638	807,401
FY 2012	$47.26	1.041582	45.37	5,753,783	5,678,024	(75,759)
FY 2013	$50.73	1.062788	47.73	6,176,247	5,793,626	(382,621)
FY 2014	$52.47	1.084313	48.39	6,388,088	5,910,966	(477,122)
FY 2015	$54.20	1.106094	49.00	6,598,711	6,029,702	(569,009)
Averages	$47.13		44.64	5,737,550.48	Total Difference	(1)
Program Case Price Adjustment - Note 3			0.14	(286,204.00)		
7(b)(2) Case Pricing - 2010$$			44.78	5,451,346.48		

Projected Average Annual Energy Output[3]	121,747
Cost per MWh	44.775865

Notes:

Note 1 - Projected Contract Pricing MWH - $39.05 at contract cap rate, cost of power is expected to be at the current contract cap during the remaining years of the current contract that expires on September 30, 2011. Only one month in FY 2007 and one month in FY 2008 were billed at a rate below the contract cap.

Note 2 - Projected new contract's floor and cap amounts are projected to be $40.32/MWh and $54.20/MWh respectively, a 39% increase over the current contract pricing. It is anticipated that the new power purchase contract would cover the five-year period 10/01/11 through 09/30/16. Projected average prices for the last 4-years of the rate test period under the new contract:

FY 2012 - $47.26 - Average price at the midpoint of the floor and cap.
FY 2013 - $50.73 - 25% of the time the pricing would be at the floor and 75% of the time pricing would be at the cap.
FY 2014 - $52.47 - 12.5% of the time pricing would be at the floor, 87.5% percent of the time pricing would be at the cap.
FY 2015 - $54.20 - 100% of the time the pricing would be at the contract cap.

These pricing assumptions will be revised as needed for the Final Studies pending the negotiation of a new contract between Idaho Falls Power and BPA.

BPA's 2010 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Idaho Falls Hydro Project Resource for FY 2010-2015

Purchase Power Contract

Notes - continued:

Note 3 - The projected average annual energy output/purchase amount from the Idaho Falls Project is projected at the seven-year average of FY 2002-2008 which was 121,747 MWhs. This results in an Average Hourly Energy amount of 13.9aMW. The White Book average energy amounts (18.5 aMW -1937 Water) for this resource are overstated, they are currently being reviewed and are expected to be revised downward to approximately 12.0 aMW - 1937 Water Year, for the Final Rate Case Study documentation.

Historical Generation / Purchases from IFP

W/P Reference		Annual Energy - MWh	Capacity Factor @18 aMW	Average Hourly Energy
	2002	111,255	70.56%	
	2003	113,442	71.94%	
	2004	110,924	70.35%	
	2005	119,434	75.74%	
	2006	140,771	89.28%	
	2007	140,898	89.36%	
	2008	115,508	73.25%	
	7-Year Average	121,747	77.21%	13.90

Table A-4: Regional Independent Hydro Projects, PNW Loads and Resource Study, 2009 - 2010 Fiscal Years, [51] 2007 Final Supplemental Rate Case (Final), 1937 Water Year, 7/17/2008

Projected annual hydro production for Idaho Falls Resource = 18.5 aMW 8,760 = 162,060

2007 BPA White Book Resource Values Table 5, page 23

Date in Service	1982	Total Annual Energy @ 18	157,680
Capacity Peak MW	18	Total Annual Energy @ 19	166,440
Firm energy aMW	19	LARIS average @ 18.5 aMW	162,060

Note 4 - Due to model escalation of O&M (escalation of the contract price amount by annual inflation), the average annual power purchase cost was decreased from $5,737,550 to $5,451,346 a difference of ($286,204). This resulted in a increase in the projected average annual cost per MWh of $0.14 to $44.78 (stated in 2010 $$$) that is applicable to the 7(b)(2) Case amount. This adjustment was necessary so that the average escalated rate during the rate test period was equal to the average Program Case rate, so that the average cost for this resource was similar between the Program Case and the 7(b)(2) Case.

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Idaho Falls Hydro Project Resource for FY 2010-2015
Purchase Power Contract

Idaho Falls Bulb Turbine Power Purchase Contract - Projected Cost Comparisons
Initial Rate Proposal and Projected Final Rate Proposal Amounts

Current IPR - Program Case Amounts - Initial Rate Proposal:

	Annual Energy Purchased MWh	Contract Purchase Price	Annual Purchased Power Cost	Other Costs	Total Cost
FY2010	162,060	$39.05	$6,328,443	$108,000	$6,436,443
FY2011	162,060	$39.05	$6,328,443	$108,000	$6,436,443
FY2012	162,060	$39.05	$6,328,443	$108,000	$6,436,443
FY2013	162,060	$39.05	$6,328,443	$108,000	$6,436,443
FY2014	162,060	$39.05	$6,328,443	$108,000	$6,436,443
FY2015	162,060	$39.05	$6,328,443	$108,000	$6,436,443

(A) - **7(b)(2) Case** Initial Proposal - Adjusted FY 2010 Power Purchase Cost Amount = $6,115,376

Preliminary Projected - Program Case Amount - Final Rate Proposal

	Annual Energy Purchased MWh	Contract Purchase Price	Annual Purchased Power Cost	Other Costs	Total Cost	Increase (Decrease) In Annual Power Purchase Costs
FY2010	121,747	$39.05	$4,754,237	$0	$4,754,237	($1,682,206)
FY2011	121,747	$39.05	$4,754,237	$0	$4,754,237	($1,682,206)
FY2012	121,747	$47.26	$5,753,783	$0	$5,753,783	($682,660)
FY2013	121,747	$50.73	$6,176,247	$0	$6,176,247	($260,196)
FY2014	121,747	$52.47	$6,388,088	$0	$6,388,088	($48,355)
FY2015	121,747	$54.20	$6,598,711	$0	$6,598,711	$162,268

(B) - **7(b)(2) Case** Adjusted FY 2010 Projected Final Rate Case Power Purchase Cost Amount = 5,451,346

Preliminary Projected Decrease in 7(b)(2) Case Adjusted FY 2010 Power
Purchase Cost Amount Between Initial Proposal Cost and Final Proposal Cost (B-A) = ($664,029.52)

AUTHENTICATED Contract No. 06PB-11734

POWER PURCHASE AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

IDAHO FALLS POWER

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This POWER PURCHASE AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and the CITY OF IDAHO FALLS, doing business as IDAHO FALLS POWER (Idaho Falls) a municipal corporation organized under the laws of the State of Idaho. BPA and Idaho Falls are sometimes referred to individually as "Party" and collectively as "Parties."

RECITALS

BPA is authorized by Federal law, including the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501, the "Northwest Power Act") and other applicable laws, to dispose of electric power generated at various Federal hydroelectric projects in the Pacific Northwest or acquired from other resources.

Idaho Falls owns and operates hydro generation units in and around the City of Idaho Falls collectively known as the Bulb Turbine Project (Project). BPA currently purchases all of the Project power output under Power Purchase Agreement No. 00PB-10710 as amended, which terminates at 2400 hours on September 30, 2006.

The Parties agree:

1. TERM

This Agreement shall take effect on the date signed by BPA and Idaho Falls. Power deliveries shall commence on the hour beginning 0000 on October 1, 2006, and continue through the hour ending 2400 on September 30, 2011.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in the body of this Agreement.

(a) "Contracted Power" means the metered, monthly Project Power Output minus the monthly Station Service, both in MWh, delivered to BPA at the Point of Receipt.

(b) "Federal System" means the facilities of the Federal Columbia River Power System, including the Federal generating facilities for which BPA is designated as marketing agent; the federal facilities under the jurisdiction of BPA; and any other facilities:

(1) from which BPA receives all or a portion of the generating capability (other than Station Service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability.

(2) which BPA may use under contract or license; or

(3) to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

(c) "Operating Year" means the period that begins each August 1 and which ends the following July 31. For instance, Operating Year 2007 begins August 1, 2006, and continues through July 31, 2007.

(d) "Point of Receipt" means the point in Idaho Falls' Sugarmill Substation where the 46 kV facilities of Idaho Falls and Rocky Mountain Power

(formally PacifiCorp and Utah Power & Light), or its successor, are connected, where Contracted Power will be made available to BPA.

(e) "Alternate Points of Receipt" (APOR) means the point in Idaho Falls' (1) Westside Substation where the 46 kV facilities of Idaho Falls and the Rocky Mountain Power are connected or the (2) Project's individual units' high-side transformer buses at 46kV.

(f) "Power Business Line" or "PBL" means that portion of the BPA organization or its successor that is responsible for the management and sale of BPA's Federal power.

(g) "Project" means the four hydro generation units owned and operated by Idaho Falls Power in and around the City of Idaho Falls collectively known as the Bulb Turbine Project ***pursuant*** to FERC Project No. 2842. The Project has a combined capacity of 24,600 kW. Specifically the units are: (1) Upper Plant, located at river mile 805, with a 7,200 kW nameplate capacity; (2) City Plant, located at river mile 800, with a 7,200 kW nameplate capacity; (3) Lower Plant, located at river mile 798, with a 7,200 kW nameplate capacity; and (4) Old Lower Plant, located at river mile 798, 2 units with a combined 3,000 kW installed capacity.

(h) "Project Power Output" means the amount of energy generated by the Project during any specified period of time as metered at the Points of Measurement.

(i) "Points of Measurement" means the four meters described in Exhibit A.

(j) "Prudent Utility Practice" means the practices, methods, and equipment, as changed from time to time, that are commonly and lawfully used in prudent engineering and operation of equipment, taking into consideration: (1) the fact that Idaho Falls is a municipal corporation under the laws of the State of Idaho with the statutory duties and responsibilities thereof; and (2) the objectives to integrate the Project with the generating resources of the Federal System, to achieve optimum utilization of such resources, and to achieve efficient and economical operation of such system.

(k) "Station Service" means the power used to serve load at the Project's facilities, including but not limited to light, space conditioning and the operation of auxiliary equipment.

(l) "Workday" means, for the purpose of scheduling, a day that the Parties both observe as a regular workday.

3. **SALE AND PURCHASE OF PROJECT POWER OUTPUT**

(a) **Power Amount**
Idaho Falls shall make available and BPA shall purchase all of the Contracted Power at the Point of Receipt for the period specified in Section 1 of this Agreement. BPA shall pay Idaho Falls the Contract Price for Contracted Power pursuant to Section 3(b).

(b) **Contract Price**
Subject to the Cap and Floor provision of Section 3(c), the Contract Price for any calendar month shall be calculated in accordance with the following methodology:

(1) Daily Dow Jones Mid-C (DJ Mid-C) heavy load and light load hour (heavy and light load hours as specified by the then current National Electric Reliability Council (NERC) or its successor's standards) prices will be weighted to develop a daily average DJ Mid-C price. The prices will be weighted by summing (a) the product of the number of heavy load hours and the daily DJ Mid-C heavy load hour price minus $1.00 and (b) the product of the number of light load hours and the daily DJ Mid-C light load hour price minus $1.00; and dividing the resulting sum by the number of hours in the day to create a daily average DJ Mid-C price.

(2) The daily average DJ Mid-C price shall be multiplied by that day's Project Power Output to derive a daily weighting factor.

(3) The daily weighting factors shall be summed for all days in the calendar month.

(4) The Contract Price is derived by dividing the sum of the weighting factors by the monthly Project Power Output.

(5) Exhibit B illustrates this process.

(c) **Cap and Floor of Contract Price**
For any calendar month, the Contract Price shall not exceed $39.05 per MWh (cap) or be less than $29.05 per MWh (floor).

(d) **Loss of the Dow Jones Mid-C Index**
In the event that the Dow Jones Mid-C Index ceases to be available to establish the price for the power pursuant to this Agreement, the Parties shall use the ICE (Intercontinental Exchange) Daily Indices for power delivered at Mid-C. In the event that the ICE Daily Indices cease to be available to establish the price for the power pursuant to this Agreement, the Parties shall have 90 days in which to agree on a new index. The last price calculated from the Dow Jones Mid-C Index or the ICE Daily Indices pursuant to this section 3(d) shall apply during that 90-day period.

Exhibit B
Contract Price Methodology

The Contract Price for any calendar month shall be based on the day-ahead Dow Jones Mid-C Index (DJ Mid-C) prices for firm power, and shall be weighted to each day's Project Power Output, in accordance with the following methodology:

- Daily DJ Mid-C heavy load and light load hour (heavy and light load hours as specified by the then current NERC Standards) prices will be weighted to develop a daily average DJ Mid-C Price. The prices will be weighted by summing (a) the product of the number of heavy load hours and the daily Mid-C heavy load hour price minus $1.00 and (b) the product of the number of light load hours and the daily Mid-C light load hour price minus $1.00; and dividing the resulting sum by the number of hours in the day to create a daily average DJ Mid-C price.
- The daily average DJ Mid-C Price shall be multiplied by that day's Project Power Output to derive a daily weighting factor.
- The daily weighting factors shall be summed for all days in the calendar month.
- The Contract Price is derived by dividing the sum of the weighting factors by the monthly Project Power Output.

$$\frac{\sum_{1}^{d}\{[HLHd*(HLHPd-\$1.00)+LLHd*(LLHPd-\$1.00)]/HOURSd\}*GENERATIONd}{\sum_{1}^{d}GENERATIONd}$$

Where:

d = the days in the month

HLHd = number of heavy load hours in the day

HLHPd = daily heavy load hour Mid-C firm energy price

LLHd = number of light load hours in the day

LLHPd = daily light load hour Mid-C firm energy price

HOURSd = HLHn + LLHn

GENERATIONd = the day's Project Power Output

BPA's 2010 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Wauna CoGen Resource for FY 2010-2015

Initial Rate Proposal Consistent with IPR Closeout and Program Case Rates[1]

Purchase Power Contract

Wauna Cogeneration Resource - Purchase Power Cost Projections:

	MWh	FY2010-$$	FY2015-$$
Annual Power Purchase Cost / 1, 2	190,000	$11,463,521	12,679,801
Projected Average Annual Energy Output - See Note 3		190,000	190,000
Average Hourly Energy aMW		21.7	21.7
Cost per MWh		$60.33	$66.74
Placed in service		1996	1996
Estimated remaining useful life = 30 years		30 years	30 years

Notes:

Note 1 - Upon additional review, it was discovered that the contract pricing amounts that were used to forecast the costs of purchased power under this contract that are outlined in the schedule presented in Note 2 below are incorrect. The cost for this resource in the 7(b)(2) resource stack is consistent with the costs for this resource that are contained in the Program Case for the Initial Rate Proposal. The decision was made to not change the purchased power amounts so that BPA's Initial Rate Proposal was consistent with the information contained in the Integrated Program Review (IPR) documentation that was finalized in a letter sent by David J. Armstrong, Executive Vice President and Chief Financial Officer to BPA's Customers and other interested parties on November 14, 2008. The correct contract price amounts and the corrected purchase power cost for this contract can be found at page 3. Unless there are additional changes that become known between the Initial Rate Proposal and the Final Rate Proposal, the revised amounts on page 3 will be used for the Final Rate Proposal. The annual purchase power cost above of $11,463,483 for FY 2010 is overstated by $287,632, the correct amount that is displayed on page 3 is $11,175,851.

Note 2 - After a resource is chosen by the rates model, its annual costs (stated in 2010 "real dollars") are inflated by the GDP deflator values contained in the model for the year the resource is first selected. These costs are escalated for each of the remaining years of the rate test period. The contract price for this resource was adjusted very slightly for the resource stack to ensure that the cost for this resource in the 7(b)(2) Case does not exceed the costs that were included for the Program Case revenue requirement. See the cost computations in the table on the succeeding page.

BPA's 2010 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Wauna CoGen Resource for FY 2010-2015

Initial Rate Proposal Consistent with IPR Closeout and Program Case Rates[1]

Purchase Power Contract

Note - 2 continued

	Program Case Nominal Pricing[1]	Cumulative GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Program Case Revenue Requirement Amounts @ 190,000 MWh Nominal Pricing	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2010	60.33	1.000000	60.33	11,462,700	11,463,521	821
FY 2011	61.75	1.020200	60.53	11,732,500	11,695,084	(37,416)
FY 2012	62.75	1.041600	60.24	11,922,500	11,940,404	17,904
FY 2013	64.05	1.062800	60.27	12,169,500	12,183,430	13,930
FY 2014	65.41	1.084300	60.32	12,427,900	12,429,896	1,996
FY 2015	66.72	1.106100	60.32	12,676,800	12,679,801	3,001
		Average	60.335203			237
7(b)(2) Case Price Adjustment			(0.000880)			
7(B)(2) Case Pricing - 2010$$[1]			60.334323			

Note 3 - Firm average annual energy purchase amount (MWh) was based on recent historical purchases from this resource as outlined below:

Historical Generation / Purchases from Wauna Project:

	Average Annual Energy - MWh
FY 2003	181,603
FY 2004	204,417
FY 2005	189,046
FY 2006	data not used - abnormal year
FY 2007	181,603
FY 2008	data not used - abnormal year
4-Year Average	189,167
Adjustment	833
	190,000

BPA's 2010 Wholesale Power Rate Case

Section 7(b)(2) Resource Stack - Wauna CoGen Resource for FY 2010-2015

Draft - Updated Cost Projections for Final Rate Proposal

Purchase Power Contract

Wauna Cogeneration Resource - Purchase Power Cost Projections:

	MWh	FY2010-$$	FY2015-$$
Annual Power Purchase Cost - See Note 1	190,000	$11,175,851	$12,361,608
Projected Average Annual Energy Output - See Note 2		190,000	190,000
Average Hourly Energy aMW		21.7	21.7
Cost per MWh		$58.82	$65.06
Placed in service		1996	1996
Estimated remaining useful life = 30 years		30 years	30 years

Note 1 - After a resource is chosen by the rates model, its annual costs (stated in 2010 "real dollars") are inflated by the GDP deflator values contained in the model to the nominal dollars of the year the resource is selected. These costs are escalated for each of the remaining years of the rate test period. The contract price for the 7(b)(2) resource stack was adjusted very slightly to ensure that the cost for this resource in the 7(b)(2) Case does not exceed the costs that were included for the Program Case revenue requirement. See the adjustment computation below:

	Contract Price - Nominal Pricing	Cumulative GDP Deflator 2010$$ Conversion	2010$$ Real Pricing	Program Case Revenue Requirement Amounts @ 190,000 MWh Nominal Pricing	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2010	$58.94	1.000000	58.94	11,198,600	11,175,851	(22,749)
FY 2011	$60.05	1.020200	58.86	11,409,500	11,401,603	(7,897)
FY 2012	$61.22	1.041600	58.77	11,631,800	11,640,766	8,966
FY 2013	$62.44	1.062800	58.75	11,863,600	11,877,694	14,094
FY 2014	$63.73	1.084300	58.78	12,108,700	12,117,975	9,275
FY 2015	$65.07	1.106100	58.83	12,363,300	12,361,608	(1,692)
		Average	58.821667			(3)
Program Case Price Adjustment			-0.001400			
7(B)(2) Case Pricing - 2010$$1			58.820267			

Note 2 - Firm average annual energy purchase amount (MWh) was based on recent historical purchases from this resource as outlined below:

Historical Generation / Purchases from Wauna Project:

	Average Annual Energy - MWh
FY 2003	181,603
FY 2004	204,417
FY 2005	189,046
FY 2006	data not used - abnormal year
FY 2007	181,603
FY 2008	data not used - abnormal year
4-Year Average	189,167
Adjustment	833
	190,000

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Wauna CoGen Resource for FY 2010-2015
Purchase Power Contract

Wauna Cogeneration - Power Purchase Contract - Projected Cost Comparisons
Initial Rate Proposal and Projected Final Rate Proposal Amounts

Current IPR - Program Case Amounts - Initial Rate Proposal:

	Annual Energy Purchased MWh	Contract Purchase Price	Annual Purchased Power Cost	Other Costs	Total Cost
FY2010	190,000	$60.33	$11,462,700	$0	$11,462,700
FY2011	190,000	$61.75	$11,732,500	$0	$11,732,500
FY2012	190,000	$62.75	$11,922,500	$0	$11,922,500
FY2013	190,000	$64.05	$12,169,500	$0	$12,169,500
FY2014	190,000	$65.41	$12,427,900	$0	$12,427,900
FY2015	190,000	$66.72	$12,676,800	$0	$12,676,800

(A) - 7(b)(2) Case Initial Proposal - Adjusted FY 2010 Power Purchase Cost Amount = $11,463,483

Preliminary Projected - Program Case Amount - Final Rate Proposal

	Annual Energy Purchased MWh	Contract Purchase Price	Annual Purchased Power Cost	Other Costs	Total Cost	Increase (Decrease) In Annual Power Purchase Costs
FY2010	190,000	$58.94	$11,198,600	$0	$11,198,600	($264,100)
FY2011	190,000	$60.05	$11,409,500	$0	$11,409,500	($323,000)
FY2012	190,000	$61.22	$11,631,800	$0	$11,631,800	($290,700)
FY2013	190,000	$62.44	$11,863,600	$0	$11,863,600	($305,900)
FY2014	190,000	$63.73	$12,108,700	$0	$12,108,700	($319,200)
FY2015	190,000	$65.07	$12,363,300	$0	$12,363,300	($313,500)

(B) - 7(b)(2) Case Adjusted FY 2010 Projected
Final Rate Case Power Purchase Cost Amount = 11,175,851

Preliminary Projected Increase in 7(b)(2) Case Adjusted FY 2010 Power
Purchase Cost Amount Between Initial Proposal Cost and Final Proposal Cost (B-A) = ($287,632)

Page 4 of 4

AUTHENTICATED

Exhibit D, Page 1 of 1
Contract No. DE-MS79-93BP94292
Procurement No. 56791
Western Generation Agency
Effective at 2400 hours on the
Effective Date

MONTHLY AMOUNTS OF BASE FIRM ENERGY, FLEXIBLE FIRM ENERGY, AND TOTAL FIRM ENERGY

(1) Month	(2) Total Hours	(3) Base Firm Energy Delivery Rate	(4) Base Firm Energy	(5) Flexible Firm Energy	(6) Total Firm Energy
		(MWh/hr)	(MWh)	(MWh)	(MWh)
JAN	744	29.710	22,104	1,488	23,592
FEB	672	28.890	19,414	1,344	20,758
MAR	744	28.590	21,271	1,488	22,759
APR	720	26.600	19,152	2,376	21,528
MAY	744	23.730	17,655	2,425	20,080
JUN	720	23.710	17,071	2,376	19,447
JUL	744	23.792	17,701	2,424	20,125
AUG	744	25.180	18,734	1,488	20,222
SEP	720	25.031	18,022	1,440	19,462
OCT	744	26.280	19,552	1,488	21,040
NOV	720	26.840	19,325	1,440	20,765
DEC	744	29.081	21,636	1,488	23,124
		TOTALS:	**231,637**	**21,265**	**236,000** 1/

1/ The total of the monthly amounts in Column 6 is 252,902 MWh. However, Total Firm Energy cannot exceed 236,000 MWh, as described in section 2(y).

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AUTHENTICATED

Exhibit E, Page 1 of 1
Contract No. DE-MS79-93BP94292
Procurement No. 56791
Western Generation Agency
Effective at 2400 hours on the
Effective Date

TOTAL FIRM ENERGY PURCHASE PRICE

Calendar Year	Total Firm Energy Purchase Price (mills/kWh)
1995	47.56
1996	48.10
1997	48.67
1998	49.26
1999	49.89
2000	50.55
2001	51.23
2002	51.96
2003	52.72
2004	53.52
2005	54.35
2006	55.23
2007	56.16
2008	57.13
2009	58.14
2010	59.21
2011	60.33
2012	61.51
2013	62.75
2014	64.05
2015	65.41
2016	66.80
2017	68.22

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WP-10 Wholesale Power Rate Case

Cost Projections for Nine Canyon Wind Project

Operating Results / Projected Operating Budgets

Portions available to Resource Stack - See Note 4:	**100% Amounts FY 2010$$**	**Non-Dedicated Portion 48.00% of Projected FY2010 Budget**	**7(b)(2) Resource Stack Amounts 0 MW**
Total Project Revenue Requirement	$18,232,540	$8,751	$ 0
Revenue Requirement Allocation to Non-Dedicated Portions			
Cost of Power ($/aMW)	$73.88	$73.88	$/aMW
Share of total projected annual generation (MWh)	246,800	118,459	0 MWh
Average energy per hour (aMW) = Projected net generation / 8760	28.17	13.52	0 aMW
Share of name plate rating (MW)	95.9MW	46.03 MW	0 MW
Capacity Factor	29.38%	29.38%	
Estimated remaining useful life = 20 years			

($ 000)

	OY_06 Actual	**OY_07 Actual**	**OY_08 Actual**	**100% of Project OY_09 Budget 2009- $$$**	**Projected FY 2010 Budget 2010- $$$**	**Non-Dedicated Portion 48.00% of Projected FY2010 Budget**
Projected Costs of Operations[1]:						
Labor & Overheads	$677	$813	$1,330	$1,715	$1,760	$844.6
Equipment / materials / Services	488	2,064	1,644	1,954	$2,005	$962.3
Insurance	118	130	117	341	$350	$167.9
Lease Payments	250	269	476	624	624	$299.5
Control Area Reserves - Within Hour Balancing Charges [2]				783	3,107	$1,491.4
Contingency / Fees	173	175		50	50	$24.0
Other Costs	336	176	148	568	$583	$279.7
Generation Taxes	34	34	51	52	$53	$25.6
Subtotal Operating Costs	$2,076	$3,661	$3,766	$6,087	$8,532	$4,095.0
Depreciation	3,798	3,697	3,993	7,222	7,222	$3,466.4
Interest Financing - Costs	5,694	5,493	6,606	6,514	6,514	$3,126.6
Gross Generation Costs	$11,568	$12,851	$14,365	$19,823	$22,268	$10,688
Renewable Energy Production Incentive Credits (REPI)	(2,299)	(1,198)	(791)	(295)	(295)	(141.6)
Net Generation Costs	$9,269	$11,653	$13,574	$19,528	$21,973	$10,546
Net Generation Costs per above	$9,269	$11,653	$13,574	$19,528	$21,973	$10,546
Less Depreciation Expense	(3,798)	(3,697)	(3,993)	(7,222)	(7,222)	(3,466)
Capital requirements	(32)	221	203	150	150	72.0
Bond Retirement / Trustee Fees	3,285	3,423	4,361	3,774	3,774	1,811.4
Interest Income	(537)	(619)	(449)	(442)	(442)	(212.2)
Projected Revenue Requirement Power Purchasers	$8,187	$10,981	$13,696	$15,788	$18,233	$8,751
Cost of Power ($/MWh)	$51.69	$70.08	$57.71	$63.97	$73.88	$73.88
Projected Annual Generation (MWh)	158,400	156,700	237,330	246,800	246,800	118,459
Average Generation per Hour (aMW)					28.17	13.52
Capacity Amount / Name plate	63.7MW	63.7MW	85.2	95.9MW	95.9MW	46.03 MW
Capacity Factor	28.39%	28.08%	31.81%	29.38%	29.38%	29.38%

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WP-10 Wholesale Power Rate Case

Cost Projections for Nine Canyon Wind Project

Operating Results / Projected Operating Budgets

Notes:

Note 1 - The actual operating results for operating years (OY) 2006, 2007, and 2008 along with the projected operating budget numbers for the resource for OY 2009 were provided by Energy Northwest, the managing entity and operator of the wind project. Phase 3 of Nine Canyon became operational in May 2007. The budget comparisons between years have not been "normalized" for the increased generation, thus they are not comparable. Variable budget costs were increased by 2.06% over FY 2009 amounts based on the projected rate of inflation continued in Global Insight's forecast, costs were increased by 2.06% over FY 2009 amounts based on the projected rate of inflation, based on Global Insight's "The U.S. Economy: The 30-Year Focus, August 2008, Base Case Scenario."

Note 2 - Starting in FY 2009, parties interconnected through BPA transmission have to self provide or purchase wind integration service and within-hour balancing reserves for wind resources through their BPA transmission interconnection agreement . This cost was added to the operating cost budget by BPA to arrive at a reasonable operating cost for this resource in the resource stack. The charges are based on BPA's 2009 Wind Integration Rate Case Revised Proposal, Attachment 1 to Settlement Agreement ACS-09, page 1, where the rate is $0.68 per kilowatt per month with the rate based on the installed capacity of the wind plant. Mathematically this is expressed:

Installed capacity = 95.9MW * 1,000 = 95,900KW/Mo. * $0.68 = $65,212 per month, times 12 months = $782,544 for OY 2009.

For the FY 2010 Initial Rate Proposal, the assumption was made that the billing determinant for these charges would be:

Wind Integration Rate on Installed Wind Capacity ($2.70/kW/month) = 95,900KW/Mo. * $2.70 * 12 months = $3,107,160

Note 3 - Analysis of the dedicated and non-dedicated portions of the Nine Canyon resource is presented below:

Energy Northwest 95.9 MW Nine Canyon Wind Power Project Allocations - Phases 1, 2, and 3

Nine Purchasers	Phase 1 MW Share	Phase 2 MW Share	Phase 3 MW Share	Total MW Share	% total	Resource Dedicated to native Load?
Benton County PUD No. 1	3.00	0.00	6.00	9.00	9.38%	Yes /A
Chelan County PUD No. 1	6.01	1.95	0.00	7.96	8.30%	Yes
Cowlitz Co PUD	2.00	0.00	0.00	2.00	2.09%	Yes
Douglas County PUD No. 1	3.01	6.80	0.00	9.81	10.23%	Quasi /B
Franklin PUD No. 1	**2.01**	**0.00**	**8.05**	**10.06**	**10.49%**	**No** /C
Grays Harbor PUD No. 1	**6.01**	**1.95**	**12.08**	**20.04**	**20.90%**	**No** /C
Lewis County PUD No. 1	1.00	0.00	5.06	6.06	6.32%	Yes
Okanogan County PUD No. 1	**12.03**	**3.90**	**0.00**	**15.93**	**16.61%**	**No** /C
Grant County PUD No. 2	12.03	0.00	0.00	12.03	12.54%	Quasi /B
Mason County PUD No. 3	1.00	1.00	1.01	3.01	3.14%	Yes
Totals	48.10	15.60	32.20	95.90	100.00%	
Non-Dedicated Portion					**48.00%**	

Note 3 - Sub-Notes:

Note A - Gloria Bender from Benton PUD informed BPA that all of its wind purchases will be used to meet their Tier 2 loads during FY2012-2029.

Note B - Resource is part of the utilities resource mix, it is not treated as a firm resource, they have not entered into specific sales contracts for the sale of specific wind energy from this resource at this time. Utility is not sure how this resource will be used during the rate test period.

Note C - Confirmed that the resource was not formally dedicated to this utility's native load through their BPA Account Executive.

Note 4 - BPA has not included in the resource stack for the WP-10 Power Rate Case any of the portions of this resource that have been purchased by BPA's 7(b)(2) Customers. BPA assumes that 7(b)(2) Customers purchasing this project are using the project as an "unspecified" resource that has been declared as serving a utility's native load pursuant to section 5(b) of the Northwest Power Act, which decreases BPA's load obligations. BPA and Consumer Owned Utilities must comply with the Bonneville Project Act, Public Law 75-329; the Pacific Northwest Consumer Power Preference Act, Public Law 88-552; and the Northwest Power Act, Public Law 96-501; before selling power outside the region. None of the customers who own shares of the Nine Canyon Wind resource have had a portion of their BPA power purchases "decremented" based upon sales of power from this resource outside the region as provided in the foregoing statutory provisions and BPA's Section 5(b)/9(c) Policy.

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	FY2010-$$	FY2010-$$		7(b)(2)
	<u>100.00%</u>	<u>4.09%</u>		Resource Stack
		"undesignated" /		<u>Amounts</u>
		"non- dedicated"		<u>0 MW</u>
7(b)(2) Case - Resource Stack Values - See Note A Below				
Total O&M - Average FY2010-2015 Non-dedicated COU & Marketer Projection =				
14.9aMW *$22.46/MWh*8,760 hour /year	$71,937,787	$2,931,819		$ 0
Cost per MWh	$22.46	$22.46		$ 0 /MW
Capital Investment - Projected Net Utility Plant FY 2010	$261,540,547			
Capital Investment - Projected Net Utility Plant FY 2015	$437,048,564			
Life	70-100 years			
Placed in service	1970			
Non-dedicated COU & Marketer average hourly energy (aMW) six-year average FY2010-2015	365.6	14.9	MW	0 MW
Average Annual Energy Output associated with Non-dedicated portion / @ 14.9aMW	3,202,656	130,524	MWh	0 MWh

			<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>
1.	2010$$ Price Conversion Factor		<u>1.000000</u>	<u>1.020232</u>	<u>1.041582</u>	<u>1.062788</u>	<u>1.084313</u>	<u>1.106094</u>
2.	**Net Costs Chargeable to Power Purchasers - per analysis below**		71,107,000	68,821,000	77,230,000	77,827,508	79,082,044	80,220,222
	Average Annual Operating Costs - Nominal $$ =	75,714,629						
3.	Projected Annual Amounts Stated in 2010$$ (line 2 divided by line 1)		71,107,000	67,456,226	74,146,826	73,229,570	72,932,856	72,525,682
4.	FY 2010 -2015 Average Total Operating Costs in 2010$$		71,899,693	71,899,693	71,899,693	71,899,693	71,899,693	71,899,693
	Operating Cost Adjustment - See Note B below		38,094	38,094	38,094	38,094	38,094	38,094
5.	Adjusted Annual Cost Amount in 2010 $$		71,937,787	71,937,787	71,937,787	71,937,787	71,937,787	71,937,787
6.	Ram Model Annual Cost Amounts Using Average Cost Pricing stated in 2010 $$ (line 5 times line 1)	Total Variance <u>2010-2015</u>	71,937,787	73,393,233	74,929,104	76,454,617	78,003,078	79,569,955
7.	Annual Variance Over / (Under) (line 6 less line 2)	1	830,787	4,572,232	(2,300,895)	(1,372,891)	(1,078,966)	(650,267)
8.	Average Firm Energy Output 365.6aMW) times the number of hours in a year (8760)		3,202,656					
9.	Projected Project Cost per MWh (line 5 divided by line 8)		$22.46					

<u>**Note B**</u> - It is necessary to make an operating adjustment so that the average total operating costs for all years of the rate test period (FY2010-2015) is equivalent to the total actual operating costs in nominal dollars (line 2) since the RAM model starts with a beginning cost of when the resource is selected from the resource stack and then escalates the cost using the fixed escalation factors at line 1 above. If a simple average of the nominal operating costs for the rate test period were used, the "starting operating cost" of the resource would have been higher at a rate of $75,714,629 in comparison to the adjusted operating cost amount of $71,937,787.

BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

Note A - BPA has not included in the resource stack for the WP-10 Power Rate Case any of the portions of Grant Co. PUD's Wanapum and Priest Rapids hydro resources that have been purchased by BPA's 7(b)(2) Customers nor the annual portions that Grant sells in its' annual auction to establish a market price for these. During BPA's process of making its' Section 5(b)/9(c) Policy Determination, concerning the portion of Grant's resources that were sold at auction and for those portions of its resources sold to regional customers that were exchanged back to Grant to be sold at market prices, Grant Co. PUD was charged with ensuring that these resources were not sold, resold, distributed for use or used outside the Pacific Northwest region except in conformance with the Bonneville Project Act, Public Law 75-329; the Pacific Northwest Consumer Power Preference Act, Public Law 88-552; and the Northwest Power Act, Public Law 96-501; before selling power from these resources outside the region. A compliance protocol was established making Grant Co. PUD responsible for the in-region use of the power when the sale at auction is made to an entity that does not have a Northwest Power Act section 5(b) contract with BPA or that does not directly serve regional consumer loads (see the copy of BPA's 5(b)/9(c) compliance protocol letter to Grant Co. PUD and Grant Co. PUD's prototype market auction contract provisions). Grant is required to monitor the sales of it's' purchaser and if requested by BPA, Grant will provide this information to BPA within 15 days of the end of the month requested. In the event that the information does not corroborate that the power was used in the region, BPA may impose a decrement upon Grant during the remaining period of time of its Subscription contract ending September 30, 2011. Similar provisions to Grant's sale at auction have also been incorporated in the contracts with the Snake River Power Association 7(b)(2) Customers.

Neither Grant Co. PUD nor BPA's other 7(b)(2) Customers who own shares of the Priest Rapids or Wanapum Hydro resources have had a portion of their BPA power purchases "decremented" based upon sales of power from these resources outside the region as provided in the foregoing statutory provisions and BPA's Section 5(b)/9(c) Policy. To ensure consistency with BPA's Section 5(b)/9(c) Policy Determinations, BPA has decided to change its 7(b)(2) resource stack policy to one of presuming that power from these resources and other 7(b)(2) customer resources that have been designated as "unspecified resources" serving a utility's native load pursuant to section 5(b) of the Northwest Power Act, (which decreases BPA's load obligations) are presumed used to meet regional loads unless there is documentation that the power is being exported out of the region only after it was offered within the region in conformance with section 9(c). Based on this 7(b)(2) resource stack policy decision, it was decided to not include any portions of the Grant Co. PUD's hydro resources in the 7(b)(2) rate stack in performing the 7(b)(2) Rate Test.

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Operating Revenues	52,000,000	57,500,000	62,000,000	62,500,000	63,000,000	63,500,000	64,000,000	66,000,000
Operating Expenses - See Notes 1, 2, and 4 below:								
Generation -	17,670,917	21,505,506	23,711,971	22,633,076	20,516,883	21,132,390	21,766,362	22,419,352
Transmission -	1,165,843	1,418,831	1,564,403	1,493,223	1,353,606	1,394,214	1,436,041	1,479,122
Administrative and General -	10,985,632	13,369,514	14,741,226	14,070,501	12,754,909	13,137,556	13,531,683	13,937,633
Administrative and General - Yakima Nation Payments	3,200,000	3,200,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000
Administrative and General - Habitat Funding Commitments	1,227,000	1,264,000	1,302,000	1,341,000	1,381,000	1,381,000	1,381,000	1,381,000
Maintenance Expenses	0	0	0	0	0	0	0	0
Depreciation Expenses	4,661,590	4,967,674	5,299,959	5,736,883	6,289,908	7,084,942	8,178,479	9,064,772
Taxes -	1,000,000	1,040,000	1,071,000	1,103,000	1,136,000	1,170,080	1,205,182	1,241,338
Other Operating Costs	0	3,578	15,250	4,801	6,601	0	0	0
Total Operating Expenses	39,910,982	46,769,103	50,105,809	48,782,484	45,838,907	47,700,182	49,898,747	51,923,217
Net Operating Income	12,089,018	10,730,897	11,894,191	13,717,516	17,161,093	15,799,818	14,101,253	14,076,783
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements	5,553,450	6,821,121	4,098,706	(1,362,326)	(2,983,576)	1,861,275	2,198,565	2,024,471
Operating Expense Percentage Change - From Prior Year	17.84%	18.58%	9.41%	-2.86%	-6.43%	4.28%	4.85%	4.26%
Average Percentage Change 2008-2012 =	7.31%							
Non Operating Revenues and (Expenses)								
Interest Income (Expense)/Gains on Debt Retirements	2,792,633	932,000	1,447,000	1,241,000	5,597,000	2,798,500	2,798,500	2,798,500
Interest on Long-Term Debt - See Note 3	(11,730,667)	(11,099,030)	(12,863,723)	(11,974,755)	(18,198,857)	(15,172,206)	(15,539,314)	(16,767,394)
Amortization of Debt Expense and Discounts	(364,636)	(364,636)	(364,636)	(364,636)	(364,636)	(364,636)	(364,636)	(91,478)
Total Non Operating Expenses	(9,302,670)	(10,531,666)	(11,781,359)	(11,098,391)	(12,966,493)	(12,738,342)	(13,105,450)	(14,060,372)
Excess (Shortfall) of Revenues Over Cost of Services	2,786,348	199,232	112,832	2,619,126	4,194,599	3,061,476	995,804	16,411

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Projected Power Costs Charged to Power Purchasers - See Notes 2-4:								
Operating Costs As Outlined Above:	39,910,982	46,769,103	50,105,809	48,782,484	45,838,907	47,700,182	49,898,747	51,923,217
Budget/Operating Cost Adjustments - See Note 4:								
Less Other noncash expenses	0	0	0	0	0	0	0	0
Less Extraordinary maintenance paid by Reserve Funds	0	0	0	0	0	0	0	0
Less Depreciation Expense	(4,661,590)	(4,967,674)	(5,299,959)	(5,736,883)	(6,289,908)	(7,084,942)	(8,178,479)	(9,064,772)
Plus Interest on Long-Term Debt	11,730,667	11,099,030	12,863,723	11,974,755	18,198,857	15,172,206	15,539,314	16,767,394
Plus capitalized interest on CWIP	1,107,193	1,201,971	1,580,479	2,000,446	2,875,863	3,955,636	3,205,972	1,602,986
Plus Principal and sinking fund payments on debt - See Note 4 below.	9,325,000	9,870,000	12,576,799	13,041,799	20,082,280	21,032,434	21,414,991	21,789,897
Plus 15% of interest and sinking fund installments	3,324,429	3,326,000	4,053,150	4,052,550	6,173,550	6,024,041	6,024,041	6,024,041
Less Interest and Other Income	(2,792,633)	(932,000)	(1,447,000)	(1,241,000)	(5,597,000)	(2,798,500)	(2,798,500)	(2,798,500)
Less 15% of prior year second series debt installments	(3,320,716)	(3,324,429)	(3,326,000)	(4,053,150)	(4,052,550)	(6,173,550)	(6,024,041)	(6,024,041)
Bond issuance costs charged (credited) to power purchasers	0	0	0	0	0			
Net Costs Chargeable to Power Purchasers	54,623,332	63,042,000	71,107,000	68,821,000	77,230,000	77,827,508	79,082,044	80,220,222
Projected Owners Operating Budgets Amounts	$54,623,332	$63,042,000	$71,107,000	$68,821,000	$77,230,000	$77,827,508	$79,082,044	$80,220,222
Average Firm Energy Output (PNW L&R Study #55) (365.6aMW) times the number of hours in a year (8760)	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656	3,202,656
Projected Project Cost per MWh	**$17.0556**	**$19.6843**	**$22.2025**	**$21.4887**	**$24.1144**	**$24.3009**	**$24.6926**	**$25.0480**
FY 2010-2015 Average =	**$23.6412**							
Percentage Increase / (Decrease)		**15.41%**	**12.79%**	**-3.21%**	**12.22%**	**0.77%**	**1.61%**	**1.44%**

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Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts	BPA Analyst's Projected Balance Sheet Amounts
Projected Balance Sheet Items -				(in whole dollars)				
Priest Rapids Hydroelectric Project:								
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Electric Plant Gross (Dam placed in service 1970)	297,015,175	316,277,895	338,038,059	370,219,142	406,312,683	468,371,453	541,317,339	577,790,281
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	38,525,441	43,520,329	64,362,165	72,187,082	124,117,541	145,891,771	72,945,885	36,472,943
Accumulated Depreciation & Amortization (15-95 year lives)	(133,178,620)	(138,146,294)	(143,446,253)	(149,183,136)	(155,473,044)	(162,557,985)	(170,736,465)	(179,801,236)
Projected Net Electric Plant	204,948,571	224,238,506	261,540,547	295,809,664	377,543,756	454,291,815	446,113,335	437,048,564
Depreciation expense	4,661,590	4,967,674	5,299,959	5,736,883	6,289,908	7,084,942	8,178,479	9,064,772
Depreciation expense as a % of gross plant	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%	1.62%
Relicensing costs	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622	29,001,622
Unamortized debt expense	2,279,294	1,914,658	1,550,022	1,185,386	820,750	456,114	91,478	0
Long-term noncash special funds	0	0	0	0	0	0	0	0
Other Deferred Charges and other assets	10,588	9,411	8,235	7,058	5,882	4,706	3,529	2,353
Projected Total Non Current Assets	236,240,075	255,164,198	292,100,426	326,003,730	407,372,010	483,754,256	475,209,965	466,052,538
Restricted Assets Current	60,228,193	56,594,006	111,740,818	108,106,631	276,329,443	272,695,256	269,061,070	265,153,725
Current and Accrued Assets	41,000,000	45,000,000	49,000,000	53,000,000	57,000,000	61,000,000	65,000,000	69,000,000
Projected Total Current Assets	101,228,193	101,594,006	160,740,818	161,106,631	333,329,443	333,695,256	334,061,070	334,153,725
Projected Total Assets	$337,468,268	$356,758,203	$452,841,244	$487,110,361	$740,701,453	$817,449,513	$809,271,034	$800,206,264
Current & Accrued Liabilities	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760	18,674,760
Current portion of long-term debt	9,870,000	12,576,799	13,041,799	20,082,280	21,032,434	21,414,991	21,789,897	22,157,304
Long-Term Debt-net of discounts	238,010,000	225,433,201	271,172,402	251,090,122	401,914,688	380,499,697	358,709,801	336,552,496
Other Noncurrent Liabilities	0	0	0	0	0	0	0	0
Projected Total Liabilities	266,554,760	256,684,760	302,888,961	289,847,162	441,621,882	420,589,448	399,174,457	377,384,561
Retained Earnings - Invested in capital assets, net of related debt	56,353,508	85,513,443	135,392,283	182,703,198	284,519,571	382,300,064	395,536,575	408,261,700
Retained Earnings/Net Assets - unrestricted other	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,001	6,000,002	6,000,003
Retained Earnings/Net assets - restricted	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000	8,560,000
Liabilities & Retained Earnings / Net Assets	$337,468,268	$356,758,203	$452,841,244	$487,110,361	$740,701,453	$817,449,513	$809,271,034	$800,206,264

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Notes:

3. Debt Service Information Continued

	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Actual/Projected Interest on Priest Rapids Bonds	12,837,860	12,286,609	11,860,124	11,426,472	10,932,869	9,222,276	9,037,831	8,857,074
Projected future levelized debt service - interest	0	0	2,577,201	2,577,201	10,107,720	9,905,566	9,707,454	9,513,305
Total Projected Interest Payments (a1)	12,837,860	12,286,609	14,437,325	14,003,673	21,040,589	19,127,842	18,745,285	18,370,379
Less Capitalized interest expenses	(1,107,193)	(1,201,971)	(1,580,479)	(2,000,446)	(2,875,863)	(3,955,636)	(3,205,972)	(1,602,986)
Capitalized interest expense/CWIP	2.93%	2.93%	2.93%	2.93%	2.93%	2.93%	2.93%	2.93%
Adjustment in interest expense (a2)	0	14,391	6,876	(28,472)	34,131	0	0	0
Total Interest Expense per operating statement - projections for 2008-2012	11,730,667	11,099,030	12,863,723	11,974,755	18,198,857	15,172,206	15,539,314	16,767,394
Actual/Projected Principal payments on Priest Rapids Bonds	9,325,000	9,870,000	10,335,000	10,800,000	11,290,000	12,038,000	12,222,445	12,403,202
Projected future levelized debt service - principal	0	0	2,241,799	2,241,799	8,792,280	8,994,434	9,192,546	9,386,695
Total Projected Principal Payments (b)	9,325,000	9,870,000	12,576,799	13,041,799	20,082,280	21,032,434	21,414,991	21,789,897
Total Debt Service (a1) + (a2) + (b)	22,162,860	22,171,000	27,021,000	27,017,000	41,157,000	40,160,276	40,160,276	40,160,276
15% of Debt Service Requirements	3,324,429	3,326,000	4,053,150	4,052,550	6,173,550	6,024,041	6,024,041	6,024,041

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	(in whole dollars)			(in whole dollars)		
	Financial Statement Information			Financial Statement Information		
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Revenues	32,064,057	30,810,541	30,707,299	30,731,802	40,183,300	46,712,241
Operating Expenses - See Notes 1, 2, and 4 below:						
Generation -	11,636,471	10,122,746	10,402,512	12,076,133	13,150,038	14,484,358
Transmission -	889,319	850,426	838,216	829,195	911,621	955,609
Administrative and General -	6,897,861	6,570,905	6,106,684	6,335,021	7,641,076	9,004,617
Administrative and General - Yakima Nation Payments	0	0	0	0	0	2,079,046
Administrative and General - Habitat Funding Commitments	0	0	0	0	1,312,487	1,204,644
Maintenance Expenses	0	0	0	0	0	0
Depreciation Expenses	4,613,571	3,681,788	5,078,184	4,687,574	4,305,179	4,494,085
Taxes -	856,948	783,116	801,631	806,559	963,642	991,863
Other Operating Costs						
Total Operating Expenses	24,894,170	22,008,981	23,227,227	24,734,482	28,284,043	33,214,221
Net Operating Income	7,169,887	8,801,560	7,480,072	5,997,320	11,899,257	13,498,020
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements		(2,885,189)	1,218,246	1,507,255	2,237,074	2,958,976
Operating Expense Percentage Change - From Prior Year		-11.59%	5.54%	6.49%	9.04%	10.46%
Average Percentage Change 2003-2007 =	3.9881%					
Non Operating Revenues and (Expenses)						
Interest Income (Expense)/Gains on Debt Retirements	967,727	451,766	338,167	869,153	2,405,970	4,653,266
Interest on Long-Term Debt - See Note 3	(8,253,381)	(8,029,995)	(7,575,817)	(7,145,249)	(9,217,948)	(11,806,973)
Amortization of Debt Expense and Discounts	(614,378)	(695,559)	(694,445)	(605,700)	(1,320,974)	(1,070,590)
Total Non Operating Expenses	(7,900,032)	(8,273,788)	(7,932,095)	(6,881,796)	(8,132,952)	(8,224,297)
Excess (Shortfall) of Revenues Over Cost of Services	(730,145)	527,772	(452,023)	(884,476)	3,766,305	5,273,723

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Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

		(in whole dollars)			(in whole dollars)	
Schedule of Power Costs to Power Purchasers:		Financial Statement Information			Financial Statement Information	
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Costs As Outlined Above:	24,894,170	22,008,981	23,227,227	24,734,482	28,284,043	33,214,221
Budget/Operating Cost Adjustments - See Note 4:						
Less Other noncash expenses				0	0	(48,037)
Less Extraordinary maintenance paid by Reserve Funds	(76,008)	(68,630)	0	(1,426,967)	(157,470)	(48,438)
Less Depreciation Expense	(4,613,571)	(3,681,788)	(5,078,184)	(4,687,574)	(4,305,179)	(4,494,085)
Plus Interest on Long-Term Debt	8,253,381	8,029,995	7,575,817	7,145,219	9,217,948	11,806,973
Plus capitalized interest on CWIP	45,928	0	268,747	340,254	984,637	844,040
Plus Principal and sinking fund payments on debt - See Note 4 below.	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
Plus 15% of interest and sinking fund installments	1,926,646	1,952,249	1,955,935	1,885,136	2,727,513	3,320,716
Less Interest and Other Income	(927,793)	(506,481)	(484,994)	(732,843)	(2,451,184)	(4,480,636)
Less 15% of prior year second series debt installments	(1,985,010)	(1,926,646)	(1,952,249)	(1,955,935)	(1,885,135)	(2,727,513)
Bond issuance costs charged (credited) to power purchasers	1,314	17,861	0	0	(26,873)	0
Net Costs Chargeable to Power Purchasers	32,064,057	30,810,541	30,707,299	30,731,772	40,183,300	46,712,241
Projected Owners Operating Budget Amounts						
Average Firm Energy Output (PNW L&R Study #55) (365.6aMW) times the number of hours in a year (8760)						
Projected Project Cost per MWh						

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	Financial Statement Information (in whole dollars)			Financial Statement Information (in whole dollars)		
Selected Balance Sheet Items -						
Priest Rapids Hydroelectric Project:						
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Electric Plant Gross (Dam placed in service 1970)	$248,319,424	$250,995,893	$257,882,972	$263,274,453	$272,610,802	$278,489,734
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	4,381,441	10,183,113	8,827,546	20,746,214	29,187,118	37,050,881
Accumulated Depreciation & Amortization (15-95 year lives)	(107,042,152)	(110,725,130)	(115,853,195)	(120,564,200)	(123,894,407)	(128,517,030)
Net Electric Plant (Note 3 of 2007 F.S.)	148,245,289	153,040,452	153,443,899	166,043,043	180,490,089	189,610,161
Depreciation expense	4,613,571	3,681,788	5,078,184	4,687,574	4,305,179	4,494,085
Depreciation expense as a % of gross plant	1.86%	1.47%	1.97%	1.78%	1.58%	1.61%
Relicensing costs	15,969,761	21,479,506	25,926,488	28,055,996	28,716,130	29,001,622
Unamortized debt expense	1,747,505	2,084,600	1,853,557	2,554,017	3,008,566	2,643,930
Long-term noncash special funds	0	0	0	0	35,739,593	0
Other Deferred Charges and other assets	9,306	0	0	0	0	11,764
Total Non Current Assets	165,971,861	176,604,558	181,223,944	196,653,056	247,954,378	221,267,477
Restricted Assets Current	30,208,013	42,056,984	32,527,571	43,323,454	43,370,906	66,055,340
Current and Accrued Assets	16,200,038	7,951,490	8,182,286	16,756,206	27,102,424	36,444,046
Total Current Assets	46,408,051	50,008,474	40,709,857	60,079,660	70,473,330	102,499,386
Total Assets	$212,379,912	$226,613,032	$221,933,801	$256,732,716	$318,427,708	$323,766,863
Current & Accrued Liabilities	22,860,256	9,570,671	9,865,060	14,437,291	14,993,582	22,355,938
Current portion of long-term debt	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
Long-Term Debt-net of discounts	145,591,449	172,146,382	167,414,785	198,290,945	257,700,000	247,880,000
Other Noncurrent Liabilities	0	0	0	0	(4,401,659)	(3,408,583)
Total Liabilities	172,996,705	186,702,053	182,474,845	218,158,236	276,086,923	276,152,355
Retained Earnings - Invested in capital assets, net of related debt	27,044,403	26,970,630	29,280,193	28,295,148	28,915,376	31,690,098
Retained Earnings/Net Assets - unrestricted other	6,000,000	6,000,000	3,000,000	4,849,332	5,630,409	6,599,410
Retained Earnings/Net assets - restricted	6,338,804	6,940,349	7,178,763	5,430,000	7,795,000	9,325,000
Total Liabilities & Retained Earnings / Net Assets	$212,379,912	$226,613,032	$221,933,801	$256,732,716	$318,427,708	$323,766,863

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Notes:

1. The financial information for the years 2002 -2007 was from Grant County PUD No. 2's audited financial statements (FS), primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2009-2012 were based on the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008. The projected Net Power Costs Chargeable to Power Purchasers for the Wanapum Development for FY2009-2012 agrees to page 20 of the Proforma report. Variable operating expenses were trended and adjusted to agree with the Proforma budget information. The debt service information was taken from page 83 of the 2007 FS notes in addition to the information presented on pages 20 and 21 of the Priest Rapids Project Final Proforma budget information dated December 1, 2008. The amounts paid under the Yakima Nation and Habitat settlements that are outlined in Note 7 - Commitments on pages 85-86 of the 2007 FS. Depreciation expense was based on a composite depreciation rate of 1.59% (average of 2006 and 2007 rates) per Note 1 - Organization and Accounting policies of the 2007 FS on page 115. Depreciation expense was calculated on the average of the beginning and ending projected balances of gross utility plant. Capitalized interest expense relating to the average of the beginning and ending year balances for projected construction work in progress (CWIP) was computed using an interest rate of 4.93% which is the 3-year (2005-2007) average of capitalized interest expense divided by the average of the beginning and ending projected CWIP balances for the year, see Note 3 below.

3. Debt Service Information
The actual interest (a) and principal (b) on the Priest Rapids Bonds for the years 2002-2007 was taken from the Operating Statement and the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2008-2015 on the Wanapum Revenue Bonds was obtained from Note 5 of the 2007 financial statements at page 128, Schedule of Debt Service Requirements. A portion of the information for 2009-2012 was from the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008, page 20 the Net Power Costs Charged to Power Purchasers.

	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Actual/Projected Interest on Priest Rapids Bonds	8,052,724	7,511,045	7,683,777	9,757,101	6,216,854	11,360,078
Projected future levelized debt service - interest	0	0	0	0	0	0
Total Projected Interest Payments (a)	8,052,724	7,511,045	7,683,777	9,757,101	6,216,854	11,360,078
Less Capitalized interest expenses	(45,928)	0	(268,747)	(340,255)	(984,636)	(844,040)
Capitalized interest expense/CWIP				2.30%	3.94%	2.55%
Adjustment in interest expense	246,585	518,950	160,787	(2,271,627)	3,985,730	1,290,935
Total Interest Expense per operating statement - projections for 2008-2012	8,253,381	8,029,995	7,575,817	7,145,219	9,217,948	11,806,973
Actual/Projected Principal payments on Priest Rapids Bonds	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
Projected future levelized debt service - principal	0	0	0	0	0	0
Total Projected Principal Payments (b)	4,545,000	4,985,000	5,195,000	5,430,000	7,795,000	9,325,000
Total Debt Service (a) + (b)	12,597,724	12,496,045	12,878,777	15,187,101	14,011,854	20,685,078
15% of Debt Service Requirements		1,874,407	1,931,817	2,278,065	2,101,778	3,102,762

4. The Priest Rapids Power Sales Contracts (covering the Priest Rapids and Wanapum Developments) provide that each power purchaser will be obligated to make payments equal to annual power costs, which include all operating expenses and debt service on the Parity Bonds and debt service coverage (currently 15% of annual debt service) less any interest earnings, for the life of the new contracts, multiplied by the percentage of output or revenue, as applicable, that the purchaser is entitled to that year. The above debt service provisions take the place of recovering depreciation expense from power purchasers and thus depreciation is subtracted from the schedule of power costs charged purchasers. Extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and the Construction Fund and are not recovered from power purchasers.

	A	B	C	D	E	F	G	H	I	J
1	**BPA's 2010 Wholesale Power Rate Case**									
2	**Grant's Priest Rapids Allocation for 2010-2015 - Received from Grant PUD 12/22/08**									
3										
4	**Priest Rapids Dam, Project Owner = Grant County PUD, FERC License Exp. 3/31/2052,**									
5	**New Purchaser Agreements became effective 11/01/2005.**									
6										
7	**Grant County PUD's Allocation Amounts prepared by Michiko Sell of Grant PUD**									
8	**Priest Rapids**									
9	**Name**		**12-15 %'s**	**10-11 %'s**	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**
10	Avista Corp (WWP Division)		0.0364	0.0376	13.7	13.7	13.3	13.3	13.3	13.3
11	Clearwater Power	**	0.0011	0.0011	0.4	0.4	0.4	0.4	0.4	0.4
12	Cowlitz County PUD #1		0.0103	0.0179	6.5	6.5	3.8	3.8	3.8	3.8
13	Eugene Water & Electric Board		0.0102	0.0105	3.8	3.8	3.7	3.7	3.7	3.7
14	Fall River Electric Coop	**	0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
15	Forest Grove, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
16	Grant County PUD #2		0.6347	0.6168	225.3	225.5	232.1	232.1	232.1	232.1
17	Idaho County L & P	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
18	Kittitas County PUD #1		0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
19	Kootenai Electric Coop	**	0.0019	0.0019	0.7	0.7	0.7	0.7	0.7	0.7
20	Lost River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
21	Lower Valley Energy	**	0.0025	0.0025	0.9	0.9	0.9	0.9	0.9	0.9
22	McMinnville, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
23	Milton-Freewater, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
24	Northern Lights	**	0.0017	0.0017	0.6	0.6	0.6	0.6	0.6	0.6
25	Pacific Power		0.0827	0.0855	31.2	31.3	30.2	30.2	30.2	30.2
26	Portland General Electric		0.0827	0.0855	31.2	31.3	30.2	30.2	30.2	30.2
27	Puget Sound Energy		0.0477	0.0493	18.0	18.0	17.4	17.4	17.4	17.4
28	Raft River Electric Coop	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
29	Salmon River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
30	Seattle City Light		0.0202	0.0209	7.6	7.6	7.4	7.4	7.4	7.4
31	Tacoma Public Utilities		0.0204	0.0211	7.7	7.7	7.5	7.5	7.5	7.5
32	United Electric Coop	**	0.0007	0.0007	0.3	0.3	0.3	0.3	0.3	0.3
33	Unknown Marketer	**	0.0300	0.0300	11.0	11.0	11.0	11.0	11.0	11.0
34	**Priest Rapids After Encroachment**		**1.00**	**0.9998**	**365.2**	**365.6**	**365.7**	**365.7**	**365.6**	**365.6**
35										
36	COUs not Dedicated to Regional Loads and Market Purchaser Allocations - **				14.9	14.9	14.9	14.9	14.9	14.9
37	Other Power Allocations				350.3	350.7	350.8	350.8	350.8	350.7
38	TOTAL			**365.6**	365.2	365.6	365.7	365.7	365.6	365.6
39	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation FY2010-2015 =			**14.9**						
40										
41	**Priest Rapids Allocation Percentage Shares:**									
42	COUs not Dedicated to Regional Loads and Market Purchaser Allocations - **				4.07%	4.07%	4.07%	4.07%	4.07%	4.07%
43	Other Power Allocations				95.93%	95.93%	95.93%	95.93%	95.93%	95.93%
44	TOTAL				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
45	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation Percentage FY2010-2015				**4.07%**					
46										
47					Page 1 of 1					
48										
49										
50										

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

	FY2010-$$ 100.00%	FY2010-$$ 4.09% "undesignated" / "non- dedicated"		7(b)(2) Resource Stack Amounts 0 MW
7(b)(2) Case - Resource Stack Values - See Note A Below				
Total O&M - Average FY2010-2015 Non-dedicated COU & Marketer Projection = 14.8aMW *$28.64 * 8,760 hour /year	$91,441,702	$3,712,859		$ 0
Cost per MWh per line 9 below -	$28.64	$28.64	$/MW	$ 0 /MW
Capital Investment - Projected Net Utility Plant FY 2010	$468,912,222			
Capital Investment - Projected Net Utility Plant FY 2015	$693,553,067			
Life	70-100 years			
Placed in service	1963			
Non-dedicated COU & Marketer average hourly energy (aMW) six-year average FY2010-2015	364.5	14.8	MW	0 MW
Average Annual Energy Output associated with Non-dedicated portion / @ 14.8aMW	3,193,020	129,648	MWh	0 MWh

		2010	2011	2012	2013	2014	2015
1. 2010$$ Price Conversion Factor		1.000000	1.020232	1.041582	1.062788	1.084313	1.106094
2. **Net Costs Chargeable to Power Purchasers - per analysis below**		90,209,000	87,704,000	98,461,000	99,054,312	100,396,305	101,630,557
Average Annual Operating Costs - Nominal $$ =	96,242,529						
3. Projected Annual Amounts Stated in 2010$$ (line 2 divided by line 1)		90,209,000	85,964,761	94,530,243	93,202,325	92,589,782	91,882,387
4. FY 2010 -2015 Average Total Operating Costs in 2010$$		91,396,416	91,396,416	91,396,416	91,396,416	91,396,416	91,396,416
Operating Cost Adjustment - See Note B below		45,286	45,286	45,286	45,286	45,286	45,286
5. Adjusted Annual Cost Amount in 2010 $$		91,441,702	91,441,702	91,441,702	91,441,702	91,441,702	91,441,702
6. Ram Model Annual Cost Amounts Using Average Cost Pricing stated in 2010 $$ (line 5 times line 1)		91,441,702	93,291,751	95,244,031	97,183,144	99,151,427	101,143,118
7. Annual Variance Over / (Under) (line 6 less line 2)		1,232,703	5,587,751	(3,216,969)	(1,871,168)	(1,244,878)	(487,439)
Total of Annual Variances =	(0)						
8. Average Firm Energy Output - 364.5aMW times the number of hours in a year (8760)		3,193,020	MWh				
9. Projected Project Cost per MWh (line 5 divided by line 8)		$28.64					

Note B - It is necessary to make an operating adjustment so that the average total operating costs for all years of the rate test period (FY2010-2015) is equivalent to the total actual operating costs in nominal dollars (line 2) since the RAM model starts with a beginning cost of when the resource is selected from the resource stack and then escalates the cost using the fixed escalation factors at line 1 above. If a simple average of the nominal operating costs for the rate test period were used, the "starting operating cost" of the resource would have been higher at a rate of $96,242,259 in comparison to the adjusted operating cost amount of $91,441,702.

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's 2010 Wholesale Power Rate Case
Section 7(b)(2) Resource Stack - Operating Cost Projections

<u>Note A</u> - BPA has not included in the resource stack for the WP-10 Power Rate Case any of the portions of Grant Co. PUD’s Wanapum and Priest Rapids hydro resources that have been purchased by BPA's 7(b)(2) Customers nor the annual portions that Grant sells in its’ annual auction to establish a market price for these. During BPA’s process of making its’ Section 5(b)/9(c) Policy Determination, concerning the portion of Grant’s resources that were sold at auction and for those portions of its resources sold to regional customers that were exchanged back to Grant to be sold at market prices, Grant Co. PUD was charged with ensuring that these resources were not sold, resold, distributed for use or used outside the Pacific Northwest region except in conformance with the Bonneville Project Act, Public Law 75-329; the Pacific Northwest Consumer Power Preference Act, Public Law 88-552; and the Northwest Power Act, Public Law 96-501; before selling power from these resources outside the region. A compliance protocol was established making Grant Co. PUD responsible for the in-region use of the power when the sale at auction is made to an entity that does not have a Northwest Power Act section 5(b) contract with BPA or that does not directly serve regional consumer loads (see the copy of BPA’s 5(b)/9(c) compliance protocol letter to Grant Co. PUD and Grant Co. PUD’s prototype market auction contract provisions). Grant is required to monitor the sales of it’s’ purchaser and if requested by BPA, Grant will provide this information to BPA within 15 days of the end of the month requested. In the event that the information does not corroborate that the power was used in the region, BPA may impose a decrement upon Grant during the remaining period of time of its Subscription contract ending September 30, 2011. Similar provisions to Grant’s sale at auction have also been incorporated in the contracts with the Snake River Power Association 7(b)(2) Customers.

Neither Grant Co. PUD nor BPA’s other 7(b)(2) Customers who own shares of the Priest Rapids or Wanapum Hydro resources have had a portion of their BPA power purchases "decremented" based upon sales of power from these resources outside the region as provided in the foregoing statutory provisions and BPA’s Section 5(b)/9(c) Policy. To ensure consistency with BPA’s Section 5(b)/9(c) Policy Determinations, BPA has decided to change its 7(b)(2) resource stack policy to one of presuming that power from these resources and other 7(b)(2) customer resources that have been designated as “unspecified resources” serving a utility’s native load pursuant to section 5(b) of the Northwest Power Act, (which decreases BPA's load obligations) are presumed used to meet regional loads unless there is documentation that the power is being exported out of the region only after it was offered within the region in conformance with section 9(c). Based on this 7(b)(2) resource stack policy decision, it was decided to not include any portions of the Grant Co. PUD’s hydro resources in the 7(b)(2) rate stack in performing the 7(b)(2) Rate Test.

Projections of Wanapum Hydroelectric Project Annual Operating Costs
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	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Operating Revenues	59,500,000	69,000,000	74,500,000	75,000,000	76,000,000	79,000,000	83,500,000	87,500,000
Operating Expenses - See Notes 1, 2, and 4 below:								
Generation - *	17,181,606	21,631,642	23,621,753	22,889,479	21,271,193	21,909,329	22,566,608	23,243,607
Transmission - *	1,325,012	1,668,190	1,821,663	1,765,192	1,640,393	1,689,605	1,740,293	1,792,502
Administrative and General - *	11,918,573	15,005,484	16,385,988	15,878,022	14,755,446	15,198,110	15,654,053	16,123,674
Administrative and General - Yakima Nation Payments	3,200,000	3,200,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000	2,400,000
Administrative and General - Habitat Funding Commitments	1,227,000	1,264,000	1,302,000	1,341,000	1,381,000	1,381,000	1,381,000	1,381,000
Maintenance Expenses	0	0	0	0	0	0	0	0
Depreciation Expenses	7,160,698	7,358,570	7,699,790	8,397,164	9,486,830	10,863,849	12,244,009	13,210,303
Taxes - *	1,014,175	1,019,000	1,050,000	1,081,000	1,113,000	1,146,390	1,180,782	1,216,205
Other Operating Costs	0	5,411	12,945	19,157	5,818	0	0	0
Total Operating Expenses	43,027,064	51,152,297	54,294,140	53,771,014	52,053,680	54,588,282	57,166,744	59,367,291
Net Operating Income	16,472,936	17,847,703	20,205,860	21,228,986	23,946,320	24,411,718	26,333,256	28,132,709
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements	6,733,535	8,088,233	3,903,843	(562,126)	(1,757,334)	2,534,602	2,578,463	2,200,547
Operating Expense Percentage Change - From Prior Year	21.13%	20.95%	8.14%	-1.08%	-3.42%	5.10%	4.94%	4.02%
Average Percentage Change 2008-2012	9.14%							
Non Operating Revenues and (Expenses)								
Interest Income (Expense)/Gains on Debt Retirements	4,842,619	1,745,000	3,130,000	2,531,000	5,347,000	2,673,500	2,673,500	2,673,500
Interest on Long-Term Debt - See Note 3	(20,804,791)	(19,036,005)	(24,408,913)	(21,467,202)	(28,494,218)	(26,209,363)	(28,080,485)	(30,395,151)
Amortization of Debt Expense and Discounts	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)	(433,898)
Total Non Operating Expenses	(16,396,070)	(17,724,903)	(21,712,811)	(19,370,100)	(23,581,116)	(23,969,761)	(25,840,883)	(28,155,549)
Excess (Shortfall) of Revenues Over Cost of Services	76,866	122,800	(1,506,951)	1,858,887	365,205	441,957	492,373	(22,841)

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Projected Power Costs Charged to Power Purchasers - See Notes 2-4:	BPA Analyst's Projected Operating Budget **2008**	BPA Analyst's Projected Operating Budget **2009**	BPA Analyst's Projected Operating Budget **2010**	BPA Analyst's Projected Operating Budget **2011**	BPA Analyst's Projected Operating Budget **2012**	BPA Analyst's Projected Operating Budget **2013**	BPA Analyst's Projected Operating Budget **2014**	BPA Analyst's Projected Operating Budget **2015**
Operating Costs As Outlined Above:	43,027,064	51,152,297	54,294,140	53,771,014	52,053,680	54,588,282	57,166,744	59,367,291
Budget/Operating Cost Adjustments - See Note 4:								
Less Other noncash expenses	0	0	0	0	0	0	0	0
Less Extraordinary maintenance paid by Reserve Funds	0	0	0	0	0	0	0	0
Less Depreciation Expense	(7,160,698)	(7,358,570)	(7,699,790)	(8,397,164)	(9,486,830)	(10,863,849)	(12,244,009)	(13,210,303)
Plus Interest on Long-Term Debt	20,804,791	19,036,005	24,408,913	21,467,202	28,494,218	26,209,363	28,080,485	30,395,151
Plus capitalized interest on CWIP	1,227,056	2,115,995	4,324,591	6,757,302	8,539,252	8,558,726	5,992,242	2,996,121
Plus Principal and sinking fund payments on debt - See Note 4 below.	10,445,000	11,320,000	16,149,496	16,639,496	22,071,531	23,378,980	24,074,342	24,755,797
Plus 15% of interest and sinking fund installments	4,871,527	4,870,800	6,732,450	6,729,600	8,865,750	8,722,060	8,722,060	8,722,060
Less Interest and Other Income	(4,842,619)	(1,745,000)	(3,130,000)	(2,531,000)	(5,347,000)	(2,673,500)	(2,673,500)	(2,673,500)
Less 15% of prior year second series debt installments	(4,868,452)	(4,871,527)	(4,870,800)	(6,732,450)	(6,729,600)	(8,865,750)	(8,722,060)	(8,722,060)
Bond issuance costs charged (credited) to power purchasers	0	0	0	0	0	0	0	0
Net Power Costs Chargeable to Power Purchasers	63,503,669	74,520,000	90,209,000	87,704,000	98,461,000	99,054,312	100,396,305	101,630,557
Projected Owners Operating Budget Amounts	$63,503,669	$74,520,000	$90,209,000	$87,704,000	$98,461,000	$99,054,312	$100,396,305	$101,630,557
Average Firm Energy Output 364.5MW times the number of hours in a year (8760)	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020	3,193,020
Projected Project Cost per MWh	**$19.8883**	**$23.3384**	**$28.2519**	**$27.4674**	**$30.8363**	**$31.0221**	**$31.4424**	**$31.8290**
FY 2010-2015 Average =	**$30.1415**							
Percentage Increase / (Decrease)		**17.35%**	**21.05%**	**-2.78%**	**12.27%**	**0.60%**	**1.35%**	**1.23%**
Average Increase FY2010-2015	**5.6214%**							

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	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget
Selected Balance Sheet Items - Wanapum Hydroelectric Project:				(in whole dollars)				
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Electric Plant Gross (Dam placed in service 1963)	456,988,220	468,618,079	499,909,009	556,337,973	636,973,956	729,547,947	810,578,942	851,094,440
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	23,259,718	62,581,859	112,857,930	161,271,965	185,147,982	162,061,991	81,030,996	40,515,498
Accumulated Depreciation & Amortization (15-95 year lives)	(131,382,932)	(138,741,502)	(146,441,292)	(154,838,456)	(164,325,286)	(175,189,135)	(187,433,144)	(200,643,447)
Net Electric Plant (Note 3 of 2007 F.S.)	351,451,582	395,045,012	468,912,222	565,358,058	660,383,228	719,007,379	706,763,370	693,553,067
Depreciation expense	7,160,698	7,358,570	7,699,790	8,397,164	9,486,830	10,863,849	12,244,009	13,210,303
Depreciation expense as a % of gross plant	1.59%	1.59%	1.59%	1.59%	1.59%	1.59%	1.59%	1.59%
Relicensing costs	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303	29,058,303
Unamortized debt expense	4,077,330	3,643,432	3,209,534	2,775,636	2,341,738	1,907,840	1,473,942	1,040,044
Long-term noncash special funds	0	0	0	0	0	0	0	0
Other Deferred Charges and other assets	10,588	9,411	8,235	7,058	5,882	4,706	3,529	2,353
Total Non Current Assets	384,587,215	427,746,747	501,180,059	597,191,997	691,783,269	749,973,522	737,295,615	723,651,414
Restricted Assets Current	137,065,070	133,498,968	282,063,866	278,497,764	448,931,662	445,365,560	441,799,458	438,233,356
Current and Accrued Assets	27,000,000	31,000,000	35,000,000	39,000,000	43,000,000	47,000,000	51,000,000	55,000,000
Total Current Assets	164,065,070	164,498,968	317,063,866	317,497,764	491,931,662	492,365,560	492,799,458	493,233,356
Total Assets	$548,652,285	$592,245,715	$818,243,925	$914,689,761	$1,183,714,931	$1,242,339,082	$1,230,095,073	$1,216,884,770
Current & Accrued Liabilities	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885	30,228,885
Current portion of long-term debt	11,320,000	16,149,496	16,639,496	22,071,531	23,378,980	24,074,342	24,755,797	25,423,622
Long-Term Debt	410,710,000	394,560,504	530,052,007	507,980,476	658,601,496	634,527,154	609,771,358	584,347,736
Other Noncurrent Liabilities	0	0	0	0	0	0	0	0
Total Liabilities	452,258,885	440,938,885	576,920,388	560,280,892	712,209,361	688,830,381	664,756,039	640,000,242
Retained Earnings - Invested in capital assets, net of related debt	80,708,304	135,621,734	225,638,440	338,723,773	455,820,474	537,823,605	549,653,938	561,199,431
Retained Earnings/Net Assets - unrestricted other	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000	6,000,000
Retained Earnings/Net assets - restricted	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097	9,685,097
Total Liabilities & Retained Earnings / Net Assets	$548,652,285	$592,245,715	$818,243,925	$914,689,761	$1,183,714,931	$1,242,339,082	$1,230,095,073	$1,216,884,770

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Note 3. Debt Service Information - continued:

	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget	BPA Analyst's Projected Operating Budget
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Actual/Projected Interest on Wanapum Bonds	22,031,847	21,119,154	20,607,856	20,066,951	19,492,295	17,547,069	17,196,128	16,852,205
Projected future levelized debt service - interest	0	0	8,197,504	8,197,504	17,572,469	17,221,020	16,876,599	16,539,067
Total Projected Interest Payments (a1)	22,031,847	21,119,154	28,805,360	28,264,455	37,064,764	34,768,089	34,072,727	33,391,272
Less Capitalized interest expenses	(1,227,056)	(2,115,995)	(4,324,591)	(6,757,302)	(8,539,252)	(8,558,726)	(5,992,242)	(2,996,121)
Capitalized interest expense/CWIP - %	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%	4.93%
Adjustment in interest expense (a2)	0	32,846	(71,856)	(39,951)	(31295)	0	0	0
Total Interest Exp. - operating statement - projections 2008-2015	20,804,791	19,036,005	24,408,913	21,467,202	28,494,218	26,209,363	28,080,485	30,395,151
Actual/Projected Principal payments on Wanapum Bonds	10,445,000	11,320,000	11,885,000	12,375,000	12,930,000	13,886,000	14,236,941	14,580,864
Projected future levelized debt service - principal	0	0	4,264,496	4,264,496	9,141,531	9,492,980	9,837,401	10,174,933
Total Projected Principal Payments (b)	10,445,000	11,320,000	16,149,496	16,639,496	22,071,531	23,378,980	24,074,342	24,755,797
Total Debt Service (a1) + (a2) + (b)	32,476,847	32,472,000	44,883,000	44,864,000	59,105,000	58,147,069	58,147,069	58,147,069
15% of Debt Service Requirements	4,871,527	4,870,800	6,732,450	6,729,600	8,865,750	8,722,060	8,722,060	8,722,060

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	(in whole dollars)			(in whole dollars)		
	Financial Statement Information			Financial Statement Information		
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Revenues	$39,654,100	$37,623,004	$30,184,495	35,301,208	42,691,219	54,637,861
Operating Expenses - See Notes 1, 2, and 4 below:						
Generation - *	12,623,551	11,099,675	10,388,384	11,701,974	11,775,574	13,856,134
Transmission - *	977,237	948,778	969,101	868,489	1,042,200	1,068,558
Administrative and General - *	6,759,515	6,451,674	5,423,216	5,453,955	6,726,024	9,611,753
Administrative and General - Yakima Nation Payments	0	0	0	0	0	2,079,046
Administrative and General - Habitat Funding Commitments	0	0	0	0	1,312,487	1,204,644
Maintenance Expenses	0	0	0	0	0	0
Depreciation Expenses	4,924,752	5,031,141	5,152,363	4,907,668	5,994,813	6,358,381
Taxes - *	852,347	764,649	803,820	874,633	936,775	971,704
Other Operating Costs						
Total Operating Expenses	26,137,402	24,295,917	22,736,884	23,806,719	27,787,873	35,150,219
Net Operating Income	13,516,698	13,327,087	7,447,611	11,494,489	14,903,346	19,487,642
Expense Changes From Prior Year - Excluding Yakima & Habitat Settlements		(1,841,485)	(1,559,033)	1,069,835	2,668,667	5,391,144
Operating Expense Percentage Change - From Prior Year		-7.05%	-6.42%	4.71%	11.21%	19.40%
Average Percentage Change 2003-2007	4.3708%					
Non Operating Revenues and (Expenses)						
Interest Income (Expense)/Gains on Debt Retirements	958,126	476,575	219,143	2,760,540	2,809,745	7,940,238
Interest on Long-Term Debt - See Note 3	(7,177,897)	(7,838,985)	(6,275,562)	(9,335,290)	(11,692,267)	(17,769,525)
Amortization of Debt Expense and Discounts	(713,449)	(806,562)	(749,297)	(744,633)	(688,862)	(664,679)
Total Non Operating Expenses	(6,933,220)	(8,168,972)	(6,805,716)	(7,319,383)	(9,571,384)	(10,493,966)
Excess (Shortfall) of Revenues Over Cost of Services	6,583,478	5,158,115	641,895	4,175,106	5,331,962	8,993,676

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Row	Item	2002	2003	2004	2005	2006	2007
101	**Schedule of Power Costs to Power Purchasers:**	Financial Statement Information - (in whole dollars)					
102		**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
104	**Operating Costs As Outlined Above:**	26,137,402	24,295,917	22,736,884	23,806,719	27,787,873	35,150,219
106	**Budget/Operating Cost Adjustments - See Note 4:**						
107	Less Other noncash expenses	0	0	0	0	0	(30,139)
108	Less Extraordinary maintenance paid by Reserve Funds	(255,008)	(90,831)	0	(774,662)	(116,462)	0
109	Less Depreciation Expense	(4,924,752)	(5,031,141)	(5,152,363)	(4,907,668)	(5,994,813)	(6,358,381)
110	Plus Interest on Long-Term Debt	7,177,897	7,838,985	6,275,562	7,177,897	11,692,267	17,769,525
111	Plus capitalized interest on CWIP	487,657	299,965	1,437,425	3,000,691	2,586,136	3,762,460
112	Plus Principal and sinking fund payments on debt - See Note 4 below.	10,955,000	9,924,804	5,180,000	6,900,000	8,870,000	10,445,000
113	Plus 15% of interest and sinking fund installments	2,793,083	2,614,184	1,933,948	2,882,732	3,400,356	4,868,452
114	Less Interest and Other Income	(1,014,294)	(584,986)	(334,189)	(3,065,939)	(2,651,406)	(7,568,919)
115	Less 15% of prior year second series debt installments	(1,711,094)	(1,675,494)	(1,892,772)	(1,927,257)	(2,882,732)	(3,400,356)
116	Bond issuance costs charged (credited) to power purchasers	8,209	31,606	0	51,303	0	0
117	**Net Costs Chargeable to Power Purchasers**	39,654,100	37,623,009	30,184,495	33,143,816	42,691,219	54,637,861
119	Projected Owners Operating Budget Amounts						
120	Average Firm Energy Output (PNW L&R Study #55) (364.5MW) times the number of hours in a year (8760)						
121	Projected Project Cost per MWh						

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Selected Balance Sheet Items - Wanapum Hydroelectric Project:	Financial Statement Information (in whole dollars)			Financial Statement Information (in whole dollars)		
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Electric Plant Gross (Dam placed in service 1963)	258,738,862	$263,178,360	$272,017,524	$274,022,058	$344,636,849	$443,728,502
Land and land rights	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695
Construction work in progress - See Note 3	9,865,278	21,230,005	53,279,575	79,184,196	80,519,296	26,519,436
Accumulated Depreciation & Amortization (15-95 year lives)	(100,896,839)	(105,929,169)	(111,130,577)	(114,286,278)	(119,510,815)	(124,222,234)
Net Electric Plant (Note 3 of 2007 F.S.)	184,148,996	194,920,891	230,608,217	255,361,671	322,087,025	362,467,399
Depreciation expense	4,924,752	5,031,141	5,152,363	4,907,668	5,994,813	6,358,381
Depreciation expense as a % of gross plant	1.90%	1.91%	1.93%	1.80%	1.94%	1.61%
Relicensing costs	15,969,794	21,492,288	25,954,022	28,112,676	28,772,811	29,058,303
Unamortized debt expense	1,308,608	2,115,744	1,886,648	3,214,705	4,945,126	4,511,228
Long-term noncash special funds	9,306	0	33,566	0	70,478,698	0
Other Deferred Charges and other assets	0	0	0	0	0	11,764
Total Non Current Assets	201,436,704	218,528,923	258,482,453	286,689,052	426,283,660	396,048,694
Restricted Assets Current	18,796,718	30,027,733	27,831,707	89,902,639	109,348,485	147,918,391
Current and Accrued Assets	18,027,531	17,559,743	8,415,820	12,591,936	19,571,040	23,816,265
Total Current Assets	36,824,249	47,587,476	36,247,527	102,494,575	128,919,525	171,734,656
Total Assets	$238,260,953	$266,116,399	$294,729,980	$389,183,627	$555,203,185	$567,783,350
Current & Accrued Liabilities	24,983,524	9,156,639	40,633,275	18,515,358	26,192,013	34,265,756
Current portion of long-term debt	11,025,000	4,905,000	5,180,000	6,900,000	8,870,000	10,445,000
Long-Term Debt	137,185,000	181,560,000	176,380,000	283,600,000	432,885,000	422,030,000
Other Noncurrent Liabilities	(6,198,995)	(6,325,429)	(5,805,229)	(3,898,842)	1,365,441	2,208,158
Total Liabilities	166,994,529	189,296,210	216,388,046	305,116,516	469,312,454	468,948,914
Retained Earnings - Invested in capital assets, net of related debt	62,243,317	46,924,797	69,734,677	72,784,379	72,288,236	81,279,121
Retained Earnings/Net Assets - unrestricted other	1,369,023	23,097,621	1,500,000	1,500,000	4,732,495	7,055,122
Retained Earnings/Net assets - restricted	7,654,084	6,797,771	7,107,257	9,782,732	8,870,000	10,500,193
Total Liabilities & Retained Earnings / Net Assets	$238,260,953	$266,116,399	$294,729,980	$389,183,627	$555,203,185	$567,783,350

Notes:

1. The financial information for the years 2002 -2007 was from Grant County PUD No. 2's audited financial statements (FS), primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2009-2012 were based on the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008. The projected Net Power Costs Chargeable to Power Purchasers for the Wanapum Development for FY2009-2012 agrees to page 22 of 31 of the Proforma report. Variable operating expenses were trended and adjusted to agree with the Proforma budget information. The debt service information was taken from page 128 of the 2007 FS notes in addition to the information presented on pages 22 and 23 of the Priest Rapids Project Final Proforma budget information dated December 1, 2008. The amounts paid under the Yakima Nation and Habitat settlements that are outlined in Note 7 - Commitments on pages 130-131 of the 2007 FS. Depreciation expense was based on a composite depreciation rate of 1.59% (average of 2006 and 2007 rates) per Note 1 - Organization and Accounting policies of the 2007 FS on page 115. Depreciation expense was calculated on the average of the beginning and ending projected balances of gross utility plant. Capitalized interest expense relating to the average of the beginning and ending year balances for projected construction work in progress (CWIP) was computed using an interest rate of 4.93% which is the 3-year (2005-2007) average of capitalized interest expense divided by the average of the beginning and ending projected CWIP balances for the year, see Note 3 below.

3. Debt Service Information
The actual interest (a) and principal (b) on the Priest Rapids Bonds for the years 2002-2007 was taken from the Operating Statement and the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2008-2015 on the Wanapum Revenue Bonds was obtained from Note 5 of the 2007 financial statements at page 128, Schedule of Debt Service Requirements. A portion of the information for 2009-2012 was from the 2009 Priest Rapids Project Final Proforma budget information dated December 1, 2008, page 22 the Net Power Costs Charged to Power Purchasers.

	2002	2003	2004	2005	2006	2007
Actual/Projected Interest on Wanapum Bonds	7,546,528	7,166,547	7,815,774	9,789,356	12,169,030	17,402,537
Projected future levelized debt service - interest	0	0	0	0	0	0
Total Projected Interest Payments (a)	7,546,528	7,166,547	7,815,774	9,789,356	12,169,030	17,402,537
Less Capitalized interest expenses	(487,657)	(299,965)	(1,437,425)	(3,000,691)	(2,586,136)	(3,762,460)
Capitalized interest expense/CWIP - %		1.93%	3.86%	4.53%	3.24%	7.03%
Adjustment in interest expense	119,026	972,403	(102,787)	2,546,625	2,109,373	4,129,448
Total Interest Exp. - operating statement - projections 2002-2007	7,177,897	7,838,985	6,275,562	7,177,897	11,692,267	17,769,525
Actual/Projected Principal payments on Wanapum Bonds (b)	11,570,000	19,025,000	4,905,000	5,180,000	6,900,000	8,870,000
Projected future levelized debt service - principal	0	0	0	0	0	0
Total Projected Principal Payments (b)	11,570,000	19,025,000	4,905,000	5,180,000	6,900,000	8,870,000
Total Debt Service (a) + (b)	19,116,528	26,191,547	12,720,774	14,969,356	19,069,030	26,272,537
15% of Debt Service Requirements	2,867,479	3,928,732	1,908,116	2,245,403	2,860,355	3,940,881

4. The Priest Rapids Power Sales Contracts (covering the Priest Rapids and Wanapum Developments) provide that each power purchaser will be obligated to make payments equal to annual power costs, which include all operating expenses and debt service on the Parity Bonds and debt service coverage (currently 15% of annual debt service) less any interest earnings, for the life of the new contracts, multiplied by the percentage of output or revenue, as applicable, that the purchaser is entitled to that year. The above debt service provisions take the place of recovering depreciation expense from power purchasers and thus depreciation is subtracted from the schedule of power costs charged purchasers. Extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and the Construction Fund and are not recovered from power purchasers.

	A	B	C	D	E	F	G	H	I	J
1	**BPA's 2010 Wholesale Power Rate Case**									
2	**Grant's Wanapum Allocation for 2010-2015 - Received from Grant PUD 12/22/08**									
3										
4	**Wanapum Dam, Project Owner = Grant County PUD, FERC License Expires 03/31/2052,**									
5	**Existing Purchaser Agreements Expire 10/31/2009, New Contracts Provisions become effective 11/01/09.**									
6										
7	**Grant County PUD's Allocation Amounts prepared by Michiko Sell of Grant PUD**									
8	**Wanapum**									
9	Name		**12-15 %'s**	**10-11 %'s**	**FY2010**	**FY2011**	**FY2012**	**FY2013**	**FY2014**	**FY2015**
10	Avista Corp (WWP Division)		0.0364	0.0376	13.7	13.7	13.3	13.3	13.3	13.3
11	Clearwater Power	**	0.0011	0.0011	0.4	0.4	0.4	0.4	0.4	0.4
12	Cowlitz County PUD #1		0.0103	0.0179	6.5	6.5	3.8	3.8	3.8	3.8
13	Eugene Water & Electric Board		0.0102	0.0105	3.8	3.8	3.7	3.7	3.7	3.7
14	Fall River Electric Coop	**	0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
15	Forest Grove, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
16	Grant County PUD #2		0.6347	0.6168	224.8	224.8	231.3	231.3	231.4	231.4
17	Idaho County L & P	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
18	Kittitas County PUD #1		0.0014	0.0014	0.5	0.5	0.5	0.5	0.5	0.5
19	Kootenai Electric Coop	**	0.0019	0.0019	0.7	0.7	0.7	0.7	0.7	0.7
20	Lost River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
21	Lower Valley Energy	**	0.0025	0.0025	0.9	0.9	0.9	0.9	0.9	0.9
22	McMinnville, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
23	Milton-Freewater, City of		0.0042	0.0042	1.5	1.5	1.5	1.5	1.5	1.5
24	Northern Lights	**	0.0017	0.0017	0.6	0.6	0.6	0.6	0.6	0.6
25	Pacific Power		0.0827	0.0855	31.2	31.2	30.1	30.1	30.2	30.2
26	Portland General Electric		0.0827	0.0855	31.2	31.2	30.1	30.1	30.2	30.2
27	Puget Sound Energy		0.0477	0.0493	18.0	18.0	17.4	17.4	17.4	17.4
28	Raft River Electric Coop	**	0.0004	0.0004	0.1	0.1	0.1	0.1	0.1	0.1
29	Salmon River Electric Coop	**	0.0003	0.0003	0.1	0.1	0.1	0.1	0.1	0.1
30	Seattle City Light		0.0202	0.0209	7.6	7.6	7.4	7.4	7.4	7.4
31	Tacoma Public Utilities		0.0204	0.0211	7.7	7.7	7.4	7.4	7.4	7.4
32	United Electric Coop	**	0.0007	0.0007	0.3	0.3	0.3	0.3	0.3	0.3
33	Unknown Marketer	**	0.0300	0.0300	10.9	10.9	10.9	10.9	10.9	10.9
34	**Wanapum After Encroachment**		**1.00**	**0.9998**	**364.3**	**364.3**	**364.4**	**364.4**	**364.6**	**364.7**
35										
36	COUs not Dedicated to Regional Loads and Market Purchaser Allocations - **				14.8	14.8	14.8	14.8	14.8	14.8
37	Other Power Allocations				349.5	349.5	349.6	349.6	349.8	349.8
38	TOTAL			**364.5**	364.3	364.3	364.4	364.4	364.6	364.7
39	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation FY2010-2015			**14.8**						
40										
41	Wanapum Allocation Percentage Shares:									
42	COUs not Dedicated to Regional Loads□ and Market Purchaser Allocatic				4.07%	4.07%	4.07%	4.07%	4.07%	4.07%
43	Other Power Allocations				95.93%	95.93%	95.93%	95.93%	95.93%	95.93%
44	TOTAL				100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
45	Non-dedicated COUs and Market Purchaser Energy - Six Year Average Allocation Percentage FY2010-2015				**4.07%**					
46										
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Grant County
PUBLIC UTILITY DISTRICT
Excellence in Service and Leadership

2009 Priest Rapids Project

FINAL PROFORMA (NOV - DEC)

December 1, 2008

"UNOFFICIAL" PRIEST RAPIDS POWER COST FORECAST
($000)

	2009*	2010	2011	2012
O & M EXPENSES	$ 40,757	$ 43,735	$ 41,942	$ 38,413
DEBT:				
ISSUED DEBT-INTEREST	11,836	11,402	10,908	10,377
ISSUED DEBT-PRINCIPAL	10,335	10,800	11,290	11,880
FUTURE LEVELIZED DEBT	-	4,819	4,819	18,900
15% OF DS TO SUPP R&R	3,326	4,053	4,053	6,174
EXCESS FROM SUPP R&R	(3,320)	(3,326)	(4,053)	(4,053)
TOTAL PROPOSED DEBT	22,177	27,748	27,017	43,278
TOTAL TAXES	1,040	1,071	1,103	1,136
INTEREST INCOME	932	1,447	1,241	5,597
NET POWER COSTS	**$ 63,042**	**$ 71,107**	**$ 68,821**	**$ 77,230**

** - Full Year*

PRIEST RAPIDS
CONSTRUCTION FUND
($000)

	2009*	2010	2011	2012
BEGINNING BALANCE	$ 48,085	$ 23,827	$ 40,006	$ -
RECEIPTS :				
FINANCING PROCEEDS	**-**	**58,781**		**171,857**
INTEREST INCOME	719	1,226	800	5,114
TOTAL RECEIPTS	719	60,007	800	176,971
EXPENDITURES :				
GENERATOR RESTORATION	1,105	638	1,063	29,243
TURBINES	1,786	4,736	5,713	22,141
POWER HOUSE	6,266	3,648	3,369	3,472
FISH & WILDLIFE	9,431	18,792	14,251	17,148
BUILDINGS/PROP	3,746	12,754	14,328	14,573
OTHER	1,924	2,034	1,282	1,447
TOTAL PER DETAIL	24,258	42,602	40,006	88,024
TRANSFER INT TO REV FUND	(719)	(1,226)	(800)	(5,114)
ENDING BALANCE	**$ 23,827**	**$ 40,006**	**$ -**	**$ 83,833**

** - Full Year*

"UNOFFICIAL" WANAPUM POWER COST FORECAST
($000)

	2009*	2010	2011	2012
O & M EXPENSES	$ 42,763	$ 45,545	$ 44,292	$ 41,453
DEBT:				
ISSUED DEBT-INTEREST	20,587	20,046	19,472	18,851
ISSUED DEBT-PRINCIPAL	11,885	12,375	12,930	13,540
FUTURE LEVELIZED DEBT	-	12,462	12,462	26,714
15% OF DS TO SUPP R&C	4,871	6,732	6,730	8,866
EXCESS FROM SUPP R&C	(4,860)	(4,871)	(6,732)	(6,729)
TOTAL PROPOSED DEBT	32,483	46,744	44,862	61,242
TOTAL TAXES	1,019	1,050	1,081	1,113
INTEREST INCOME	1,745	3,130	2,531	5,347
NET POWER COSTS	**$ 74,520**	**$ 90,209**	**$ 87,704**	**$ 98,461**

** - Full Year*

WANAPUM
CONSTRUCTION FUND
($000)

	2009*	2010	2011	2012
BEGINNING BALANCE	$ 85,231	$ 34,279	$ 104,843	$ -
RECEIPTS :				
FINANCING PROCEEDS	-	**152,131**	-	**174,000**
INTEREST INCOME	1,195	2,913	2,097	4,870
TOTAL RECEIPTS	1,195	155,044	2,097	178,870
EXPENDITURES :				
GENERATOR RESTORATION	6,753	30,451	43,992	28,516
TURBINES	22,229	21,212	20,206	27,481
POWERHOUSE/SWITCHYARD	12,268	11,546	16,715	16,345
FISH AND WILDLIFE	3,366	3,030	8,133	15,635
BUILDINGS/PROPERTIES	3,756	12,758	14,307	14,618
OTHER	2,580	2,570	1,490	1,917
TOTAL PER DETAIL	50,952	81,567	104,843	104,512
TRANSFER FROM R&C FUND	-	-	-	-
PAID FROM THE CONST FUND	50,952	81,567	104,843	104,512
TRANSFER INT TO REV FUND	(1,195)	(2,913)	(2,097)	(4,870)
ENDING BALANCE	**$ 34,279**	**$ 104,843**	**$ -**	**$ 69,488**

** - Full Year*

6/16/2008
CONTRACT
FOR
OPEN-MARKET SALE OF PRIEST RAPIDS PROJECT POWER

INDEX TO SECTIONS

CONTRACT
FOR
OPEN-MARKET SALE OF PRIEST RAPIDS PROJECT POWER

Executed by
PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON
And

This contract is entered into as of ____________, 2008 between Public Utility District No. 2 of Grant County, Washington (the "District"), a municipal corporation of the State of Washington, and _____________(the "Purchaser"), a ____________ corporation organized and existing under the laws of ___________________________. The District and the Purchaser are referred to as a "Party" and collectively as "Parties."

SECTION 1. TERM OF CONTRACT

Except as otherwise provided herein, this Contract shall be in full force and effect from and after it has been executed by the District and the Purchaser. Unless sooner terminated pursuant to other provisions, this Contract shall remain in effect until the end of HE 2400 (midnight) Pacific Prevailing Time "PPT", December 31, 2009. Except as otherwise provided herein, all obligations accruing under this Contract are preserved until satisfied.

SECTION 2. DEFINITIONS

As used in this Contract, the following terms when initially capitalized shall have the following meanings:

"Agreement for the Hourly Coordination of Projects on the Mid-Columbia River" (MCHC) shall mean the 1997 Agreement, as amended from time to time, with the Mid-Columbia PUD project owners, purchasers, the U.S. Department of Energy via the Bonneville Power Administration, the U.S. Department of the Army via the Army Corps of Engineers, and the U.S. Department of Interior via the Bureau of Reclamation to coordinate real time operation of the seven projects from Grand Coulee through Priest Rapids on the Columbia River.

"Bond Resolution" shall mean each and all of the resolutions adopted by the District authorizing the issuance of outstanding Debt for the Priest Rapids Project.

"Business Days" shall mean any weekday, Monday through Friday, excluding District Recognized Holidays as designated on Exhibit B of this Contract.

"Contract" shall mean this **CONTRACT FOR OPEN-MARKET SALE OF PRIEST RAPIDS PROJECT POWER**, in its' entirety.

"Defaulting Party" shall mean the Party who is responsible for an "Event of Default" as defined in Section 15.

"Electric System" shall mean the separate electric utility system of the District, including all associated generation, transmission and distribution facilities and any betterments, renewals, replacements and additions of such system, but does not include the Priest Rapids Project or any other utility properties designated as a separate utility system of the District.

"FERC" shall mean the Federal Energy Regulatory Commission or its successor.

"FERC License" shall mean the license for the Priest Rapids Project PL 2114 issued by FERC on_April 17, 2008, effective April 1, 2008.

"Guarantor" means the entity providing a guarantee pursuant to a Guarantee Agreement.

"HE" shall mean hour ending.

"Operating Agreements" shall mean any agreements to which the District is or may become a party, which provide for operation of the Priest Rapids Project, including but not limited to, the Pacific Northwest Coordination Agreement, the Agreement for the Hourly Coordination of Projects on the Mid-Columbia River, the Western Systems Coordinating Council Agreement, and the Northwest Power Pool Agreement, as such agreements currently exist or hereafter may be amended.

"Original FERC License" shall mean the Federal Power Commission License for the Priest Rapids Project issued to the District on November 4, 1955, together with amendments thereto.

"Pacific Northwest" shall have the meaning ascribed thereto in Section 3(14) of the Regional Act.

"Pacific Northwest Coordination Agreement" or "PNCA" shall mean the Agreement amongst northwest parties executed in 1997 for the coordinated operation of the Columbia River System which became effective August 1, 2003, as such Agreement may be amended from time to time.

"Pre-Schedule Day" shall mean days identified by the District pursuant to the Western Electricity Coordinating Council Interchange Scheduling and Accounting Subcommittee daily scheduling calendar.

"Priest Rapids Development" shall mean the separate utility system of the District, including a dam at the Priest Rapids Development, all generation and transmission facilities associated therewith, and all betterments, renewals, replacements, and additions to such system, as further described in Section 2(f) of Exhibit 1 of District Resolution No. 390 which is attached as Exhibit A, but shall not include any additional generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Wanapum Development or any other utility properties of the District acquired or constructed as a separate utility system.

"Priest Rapids Project Output" or "PRPO" shall mean: i.) the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services and any other product produced by the Priest Rapids Development between the start of HE 0100 P.P.T. January 1, 2009 and the end of HE 2400 (midnight) P.P.T. December 31, 2009, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements, together with ii.) the amount of capacity, energy (both firm and non-firm), pondage, reactive power, ancillary services and any other product produced by the Wanapum Development between the start of HE 0100 P.P.T November 1, 2009 and the end of HE 2400 (midnight) P.P.T. December 31, 2009, after correction for encroachment, Canadian entitlement, station and project use, and depletions required by the FERC License or other regulatory requirements

"Priest Rapids Project" shall mean the hydroelectric project on the Columbia River in the State of Washington designated by the Federal Power Commission as Project No. 2114. The Priest Rapids Project consists of the Priest Rapids Development and the Wanapum Development.

"Prudent Utility Practice" means those practices, methods and acts which: (i) when engaged in are commonly used in prudent engineering and operations to operate electric equipment and associated mechanical and civil facilities lawfully and with safety, reliability, efficiency and expedition or (ii) in the exercise of reasonable judgment considering the facts known when engaged in, could have been reasonably expected to achieve the desired result consistent with applicable law, safety, reliability, efficiency and expedition. Prudent Utility Practice is not intended to be the optimum practice, method or act, to the exclusion of all others, but rather to be a spectrum of commonly used practices, methods or acts.

"Regional Act" shall mean Public Law 96-501, the Pacific Northwest Electric Power Planning and Conservation Act.

"Uncontrollable Forces" shall mean any cause reasonably beyond the control of the Party and which the Party subject thereto has made reasonable efforts to avoid, remove or mitigate, including but not limited to acts of God, fire, flood, explosion, strike, sabotage, acts of terrorism, act of the public enemy, civil or military authority, including court orders, injunctions, and orders of government agencies (other than those of the District) with proper jurisdiction, insurrection or riot, an act of the elements, failure of equipment or contractors, or inability to obtain or ship materials or equipment because of the affect of similar causes on suppliers or carriers; provided, however, that in no event shall an Uncontrollable Force excuse the Purchaser from the obligation to pay any amount when due and owing under this contract.

"Wanapum Development" shall mean the second stage of the Priest Rapids Project as more fully described in Section 2.2 of District Resolution No. 474, which is attached as Exhibit A, but shall not include any generation, transmission and distribution facilities hereafter constructed or acquired by the District as a part of the Electric System or the Priest Rapids Development, or any other utility properties of the District acquired or constructed as a separate utility system.

The following terms are defined in the cited sections of this Contract:

"Event of Default" at Section 15(a)

"Party" and "Parties" at the Preamble
"Purchaser Allocation of Pondage" at Section 6(d)(4)
"Purchaser's PRPO" at Section 3(a)

SECTION 3. PURCHASE AND SALE OF PRIEST RAPIDS PROJECT OUTPUT/REGULATORY APPROVAL

(a) Purchaser's PRPO. The District shall make available to the Purchaser and the Purchaser shall purchase an amount of PRPO equal to the total applicable PRPO multiplied by the corresponding Purchaser's PRPO Percentage which amount is herein referred to as "Purchaser's PRPO."

(b) The Purchaser's PRPO Percentage shall be _____ % of Priest Rapids Development power for the period starting at (midnight) HE 2400, December 31, 2008 and ending at HE 2400, October 31, 2009 AND ____% of Priest Rapids Project power for the period starting at HE 2400, October 31, 2009 and ending at (midnight) HE 2400, December 31, 2009.

SECTION 4. PRPO AVAILABILITY

(a) Purchaser understands and acknowledges that PRPO availability will fluctuate and is subject to and contingent upon many factors including, but not limited to, the following: weather and precipitation levels, regulatory and environmental considerations and requirements, Operating Agreements and Uncontrollable Forces.

(b) The District may restrict deliveries of PRPO if it determines that such action is necessary to avoid exceeding the capability of the Priest Rapids Project or subjecting it or its operation to undue hazard or violating the FERC License, any applicable law, regulation, or Operating Agreement. Any such restrictions in delivery by the District shall be made pro-rata with all purchasers of PRPO and with the District's share of PRPO.

(c) The District may also restrict deliveries of PRPO in case of emergencies or in order to install equipment in, make repairs to, make betterments, renewals, replacements, and additions to, investigations and inspections of, or perform other maintenance work on the Priest Rapids Project. Any such restrictions in delivery shall be made pro-rata with all purchasers of PRPO and with the District's share of PRPO.

(d) The District will use commercially reasonable efforts to give advance notice to the Purchaser regarding any planned limit, restriction, interruption or reduction of PRPO, giving the reason therefore and stating the probable duration thereof, and shall provide timely updates concerning the same should conditions change.

(e) Notwithstanding any other provision of this Contract, the District shall at times have the right to operate the Priest Rapids Project in such manner as it deems to be in its best interests so long as the same is consistent with the FERC License, applicable laws and regulations, Prudent Utility Practice and this Contract.

(f) Notwithstanding any other provision of this Contract, the District shall have the unilateral right to restrict deliveries of PRPO as may be necessary to fulfill any non-power regulatory or other legal requirements and shall have the unilateral right to determine the amounts of spill required at the Priest Rapids Project. Any such restrictions in delivery shall be made pro-rata with all purchasers of PRPO and with the District's share of PRPO.

SECTION 5. PURCHASE PRICE AND PAYMENTS BY PURCHASER

(a) The purchase price for the Purchaser's PRPO shall be the total dollar amount submitted by Purchaser on its bid form. Purchaser shall make 12 equal monthly payments of $1/12^{th}$ of the purchase price with the first such payment due January 10, 2009.

(b) The monthly payments set forth above shall be due and payable by electronic funds transfer to the District's account, designated in writing by the District, on the 10^{th} (tenth) calendar day of each month. If the 10^{th} calendar day of the month is a Saturday, Sunday or a District Recognized Holiday as listed in Exhibit B, the next following Business Day

(c) If payment in full of any monthly payment amount set forth on a statement or revised statement is not received by the District on or before the close of business on the 10th calendar day of the month, a delayed payment charge of 2% of the unpaid amount due will be made. Any bill which remains unpaid for more than 30 calendar days after the due date shall, in addition to the delayed payment charge, accrue interest at the lesser of 1.5% per month or the maximum rate allowed by law. If the 10^{th} calendar day of the month is a Saturday, Sunday or a District Recognized Holiday as listed in Exhibit B, the next following Business Day shall be the last day on which payment may be received without the addition of the delayed-payment charge. Additionally, if payment due to the District under this Section 5 remains unpaid 3 Business Days after the due date, the District may thereafter suspend delivery of the Purchaser's PRPO until payment in full of all amounts due and owing (including any interest and delay charges) is received by the District.

(d) The payments required under this Section 5 shall be due and owing notwithstanding the fact that the actual amount of power from the PRPO Percentage made available to the Purchaser is less or more than that which was anticipated by either Party at the time of execution of this Contract. The District makes no warranties of any type as to the PRPO that will actually be produced and available, other than, that the percentage of PRPO made available to the Purchaser will at all times be in accordance with Section 3(c), and Purchaser assumes all risks associated therewith.

(e) The purchase price submitted by the Purchaser on its bid form is the total price for the Purchaser's PRPO and all rights associated with it. Except as otherwise provided in Sections 6(c) and 18 (c), the Purchaser shall not be obligated to pay any other amounts charged to or payable by the Purchaser as a result of this Contract, including any water fees, license fees, penalties, taxes, operating, administration, maintenance or capital costs, damages or any other costs whatsoever, relating to ownership or operation of the Priest Rapids Project.

SECTION 6. SCHEDULING OF DELIVERIES OF PRIEST RAPIDS PROJECT OUTPUT

(a) This Section 6 shall apply to the scheduling of the Purchaser's PRPO.

(b) Scheduling of Purchaser's PRPO shall be as requested by the Purchaser, or its designated scheduling agent, and shall be subject to the limitations set forth in this Contract.

(c) The Purchaser, or its designated scheduling agent, shall provide the District each Pre-Schedule Day, in conformance with then prevailing scheduling procedures for scheduling Pacific Northwest generating resources, hourly schedules of desired Purchaser's PRPO deliveries for the following day or days. The schedules will be completed in a time frame consistent with standard industry practices in the Pacific Northwest. Such schedule shall be based upon the probable water supply to the Priest Rapids Project (inflows) and the resulting probable output. Schedules shall be in compliance with all applicable reliability and reserves criteria as put forth by the North American Electric Reliability Council, Western Electricity Coordinating Council, and the Northwest Power Pool; as such criteria are revised from time to time. If failure to comply with reliability or reserve criteria results in costs or fees incurred by the District, Purchaser shall reimburse District for all such costs or fees. Revisions in a schedule may be made at any time upon the request of the Purchaser in accordance with Section 6(d)(9). The District will use reasonable efforts to minimize deviations from the schedule and make corrections promptly as practicable on an hourly basis under conditions as nearly equivalent as practicable to those occurring when the deviations occurred. Alternatively, the Purchaser may provide scheduling information via a dynamic electronic signal. If the Purchaser chooses this option, it shall be solely responsible for providing any and all necessary hardware or software modifications necessary for the District to incorporate this signal.

(d) Purchaser's schedules shall be in accordance with the following:

(1) Subject to the provisions of this Contract, the District shall make available to Purchaser, each hour, Purchaser's PRPO.

(2) The District shall make all determinations concerning the Priest Rapids Project maximum output and minimum discharge; and the District shall have the unilateral right to determine the maximum allowable amount of change in PRPO during any time period and the maximum number of unit starts and stops allowable during any time period. Purchaser's daily and hourly schedules shall be based on Purchaser's PRPO in accordance with the Priest Rapids Project operational parameters as established by the District from time to time.

(3) Purchaser's schedule shall not be less than Purchaser's PRPO Percentage of the minimum operating capability of the Priest Rapids Project, as determined by the District, nor shall it be greater than Purchaser's PRPO Percentage of the maximum operating capability of the Priest Rapids Project as determined by the District.

(4) Purchaser shall be entitled to utilize a share of the pondage available at the Priest Rapids Project (the "Purchaser Allocation of Pondage"), determined by multiplying the total of the pondage available by the applicable Purchaser's PRPO Percentage. The pondage available at the Priest Rapids Project shall be determined by the District from time to time on the basis of the volume of water that can be stored between the then current maximum forebay elevation and the then current minimum forebay elevation.

(5) The District will establish and maintain for Purchaser a pondage account that will reflect the use of pondage by the Purchaser. On the last hour of the term of this Contract, the Purchaser shall return the pond account balance to at least where it was on the first hour of the term of this Contract. The Purchaser may schedule more than its share of the Priest Rapids Project inflows determined in accordance with Section 6(c) if the Purchaser has sufficient amount of energy in its pond account. The amount of the energy scheduled from the pondage account shall not exceed the Purchaser Allocation of Pondage determined in accordance with Section 6(d)(4).

(6) During any hour that spill is occurring at non-federal Mid-C Projects in order to control forebay elevation, the spill is allocated in the following manner: i) if spill is due to unloaded turbines at the spilling project, that spill will be allocated to any Mid-C participant whose generation was less than their capacity during the spill hour, ii) Spill past loaded units are allocated to each Mid-C party who has a share in the spilling project.

(7) During any hour that spill is occurring at the Priest Rapids Project for fish or any other non-power purpose determined necessary or desirable by the District, the spill shall be allocated to reduce the inflow of Purchaser and other PRPO purchasers in proportion to their percentage shares of PRPO, including the District.

(8) If the Purchaser chooses not to provide scheduling information via a dynamic electronic signal, the District will provide the following maximum number of schedules or paths available to schedule Purchaser's PRPO on an hourly basis according to the following formula: the amount of daily capacity available to the Purchaser, divided by 15 (rounded up), plus 1.

(9) In the absence of dynamic scheduling pursuant to Section 6 (c) real-time schedules shall be called in at least 30 minutes prior to the start of each hour.

SECTION 7. POINT OF DELIVERY

(a) PRPO power supplied hereunder shall be approximately 230 kV, three-phase, alternating current, at approximately 60 hertz.

(b) The PRPO power to be delivered hereunder shall be made available to the Purchaser, at its option, exercisable from time to time, at any one or more of the following points:

(1) The 230 kV bus of the Bonneville Power Administration's Midway Substation;

(2) The 230 kV bus of the switchyard of the Wanapum Development;

(3) The 230 kV bus of the Vantage Substation; or

(4) At any other location mutually agreed to by the District and Purchaser.

SECTION 8. METERING AND TRANSMISSION LOSSES

(a) The District shall provide and maintain suitable meters in the generator leads of the Priest Rapids Project to indicate and record the PRPO. The actual PRPO shall be determined from totaled readings from the meters. The District or an agent of the District shall read meters and records thereof shall be made available to the Purchaser as may be reasonably requested.

(b) Purchaser shall be required to schedule an amount of energy equal to the actual losses resulting from transformation and transmission to the District.

SECTION 9. INFORMATION TO BE MADE AVAILABLE TO THE PURCHASER

(a) The Purchaser, upon at least 30 days advance written notice to the District, shall have the right at its sole cost and expense to audit or examine operating records relating to the Priest Rapids Project during the District’s normal business hours. All costs incurred by the District associated with such audit, including, but not limited to, District labor, materials and reproduction services shall be promptly reimbursed to the District by the Purchaser.

(b) The Purchaser’s representatives shall at all times be given reasonable access to the Priest Rapids Project, subject to the District’s applicable safety rules and regulations.

(c) The District shall exercise commercially reasonable efforts to provide to the Purchaser estimates and information reasonably necessary for the Purchaser to exercise its rights under this Contract.

SECTION 10. LIABILITY OF PARTIES

(a) Except as otherwise provided in this Contract, each Party hereby releases the other Party and its commissioners, officers, directors, agents and employees from any claim for loss or damage arising out of the ownership, operation, and maintenance of the Priest Rapids Project including any loss of profits or revenues, loss of use of power system, cost of capital, cost of purchased or replacement power, other substantially similar liability or other direct or indirect consequential loss or damage.

(b) The Purchaser shall have no claim of any type or right of action against the District: (i) as a result of a FERC or court order or amendment; (ii) as a result of adjustment of PRPO, and the Purchaser hereby releases the District and its commissioners, officers, agents and employees from any claim for loss or damage arising out of the events described in this paragraph.

(c) The Purchaser is purchasing output from or attributable to the Priest Rapids Project as available and scheduled by the Purchaser. The Purchaser acquires no interest in or rights to any facilities forming part of the Priest Rapids Project.

SECTION 11. NOTICES AND COMPUTATION OF TIME

(a) Any notice, demand or request provided for in this Contract shall be, unless otherwise specified herein, in writing and may be delivered by hand delivery, United States mail, overnight courier or facsimile. Notice by courier, facsimile or hand delivery shall be effective at the close of business on the day actually received, if received during business hours on a regular Business Day of the District, and otherwise shall be effective on the close of business on the next regular Business Day of the District. All notices by United States mail shall be sent certified, return receipt requested and shall be effective on the date of actual receipt by the recipient.

All notice, demand or request made by mail shall be mailed postage prepaid and addressed to:

Manager
Public Utility District No. 2 of Grant County
P.O. Box 878
30 C St S.W.
Ephrata, Washington 98823;

any notice or demand by the District to the Purchaser under this Contract shall be deemed properly given if a written copy is delivered to the Purchaser's representative specified herein by courier and the Purchaser's signature evidencing receipt thereof is obtained or if mailed postage prepaid and addressed to:

.

(b) In computing any period of time from such notice, such period shall commence at HE 2400 (midnight) PPT on the date mailed. The designations of the name and address to which any such notice or demand is directed may be changed at any time by either Party giving notice as provided above.

SECTION 12. DISTRICT'S BOND RESOLUTIONS AND LICENSE

It is recognized by the Parties that the District, in its operation of the Priest Rapids Project, must comply with the requirements of the Bond Resolution and with the FERC License together with amendments thereof from time to time made, and the District is hereby authorized to take such actions as the District determines are necessary and appropriate to comply with such Bond Resolutions and FERC License.

SECTION 13. GOVERNING LAW.

The Parties agree that the laws of the State of Washington shall govern this Contract.

SECTION 14. ASSIGNMENT OF CONTRACT

Neither the Purchaser nor the District shall by contract, operation of law or otherwise, assign this Contract or any right or interest in this Contract without the prior written consent of the other Party, which shall not be unreasonably withheld; provided, however, a Party may, without the consent of the other Party (and without relieving itself from liability hereunder) (i) transfer or assign this Contract to an affiliate of the Party provided that the affiliate's creditworthiness is equal or higher than that of the Party or (ii) transfer or assign this Contract to any person or entity succeeding to all or substantially all of the distribution and generating facilities of the Party whose creditworthiness is equal or higher than that of the Party; provided however, that in each such case, any such assignee shall agree in writing to be bound by the terms and conditions in this Contract and the transferring Party shall deliver such tax and enforceability assurance as the other Party may reasonably request.

SECTION 15. REMEDIES ON DEFAULT

(a) An "Event of Default" shall mean with respect to a Party ("Defaulting Party"):

(1) the failure by the Defaulting Party to make, when due, any payment required pursuant to this Contract if such failure is not remedied within three (3) Business Days after written notice of such failure is given to the Defaulting Party by the other Party ("the Non-Defaulting Party"). The Non-Defaulting Party shall provide the notice by facsimile to the designated contact person for the Defaulting Party and also shall send the notice by overnight delivery to such contact person; or

(2) the failure by the District to deliver PRPO to the Purchaser as required by this Contract and such failure is not cured within three (3) Business Days after written notice thereof from the Purchaser to the District; or

(3) the failure by the Defaulting Party to have made accurate representations and warranties as required this Contract and such failure is not cured within three (3) Business Days after written notice thereof to the Defaulting Party; or

(4) the institution, with respect to the Defaulting Party, by the Defaulting Party or by another person or entity of a bankruptcy, reorganization, moratorium, liquidation or similar insolvency proceeding or other relief under any bankruptcy or insolvency law affecting creditor's rights or a petition is presented or instituted for its winding-up or liquidation; or

(5) the failure by the Defaulting Party to provide adequate assurances of its ability to perform all of its outstanding material obligations to the Non-Defaulting Party under this Contract.

(6) With respect to its Guarantor, if any:

(i) if a material representation or warranty made by a Guarantor in connection with this Contract, or any transaction entered into hereunder, is false or misleading in any material respect when made or when deemed made or repeated; or

(ii) the failure of a Guarantor to make any payment required or to perform any other material covenant or obligation in any guarantee made in connection with this Contract, including any transaction entered into hereunder, and such failure shall not be remedied within three (3) Business Days after written notice; or

(iii) the institution, with respect to the Guarantor, by the Guarantor or by another person or entity of a bankruptcy, reorganization, moratorium, liquidation or similar insolvency proceeding or other relief under any bankruptcy or insolvency law affecting creditor's rights or a petition is presented or instituted for its winding-up or liquidation; or

(iv) the failure, without written consent of the other Party, of a Guarantor's guarantee to be in full force and effect for purposes of this Contract (other than in accordance with its terms) prior to the satisfaction of all obligations of such Party under each transaction to which such guarantee shall relate; or

(v) a Guarantor shall repudiate, disaffirm, disclaim, or reject, in whole or in part, or challenge the validity of, any guarantee.

(b) If an Event of Default occurs, the Non-Defaulting Party shall possess the right to terminate the Contract or seek specific performance. In the event the Non-Defaulting Party elects to terminate the Contract, it may pursue any legal or equitable remedies available at law or otherwise.

SECTION 16. CREDITWORTHINESS

Should the Purchaser's creditworthiness, financial responsibility, or performance viability be unsatisfactory to the District in the District's reasonably exercised discretion with regard to this Contract, the District may require the Purchaser to provide, at the Purchaser's option (but subject to the District's acceptance based upon reasonably exercised discretion), either (1) the posting of a letter of credit, (2) a cash prepayment, (3) the posting of other acceptable collateral or security by the Purchaser, (4) a guaranty agreement executed by a creditworthy entity; or (5) some other mutually agreeable method of satisfying the District.

All collateral posted in the form of cash or cash prepayment will be held in an interest bearing escrow account. In the event the collateral is no longer required to satisfy Purchaser's obligations, it will be returned to the Purchaser, with interest earned, on a tiered basis near the end of the term of this Contract. For each fiscal year beginning April 1 and ending March 31, deposits will earn interest calculated at the rate for the one-year Treasury Constant Maturity calculated by the U.S. Treasury, as published in the Federal Reserves Statistical Release H.15 on March 15 of each year. If March 15 falls on a non-Business Day, the District will use the rate

posted on the next Business Day. The one-year Treasury Constant Maturity rate on March 15 of each year will be applied to the next fiscal year beginning April 1 and ending March 31.

Events which may trigger the District requesting assurance due to reasonable concern about the Purchaser's creditworthiness, financial responsibility, or performance viability include, but are not limited to, the following:

(a) The Purchaser or its Guarantor has debt which is rated as investment grade and that debt falls below the investment grade rating by at least one rating agency or is below investment grade and the rating of that debt is downgraded further by at least one rating agency.

(b) Other material adverse changes in the Purchaser's financial condition occur.

(c) Substantial changes in market prices which materially and adversely impact the Purchaser's ability to perform under this Contract occur.

If the Purchaser fails to provide such reasonably satisfactory assurances of its ability to perform an obligation hereunder within three (3) Business Days of demand therefore, that will be considered an Event of Default under Section 15 of this Contract and the District shall have the right to exercise any of the remedies provided for under that Section 15. Nothing contained in this Section 16 shall affect any credit agreement or arrangement, if any, between the Parties.

SECTION 17. VENUE AND ATTORNEY FEES

Venue of any action filed to enforce or interpret the provisions of this Contract shall be exclusively in the United States District Court for the Eastern District of Washington or the Superior Court of the State of Washington for Grant County and the Parties irrevocably submit to the jurisdiction of any such court. In the event of litigation to enforce the provisions of this Contract, the prevailing Party shall be entitled to reasonable attorney's fees in addition to any other relief allowed.

SECTION 18. COMPLIANCE WITH LAW

(a) The Parties understand and acknowledge that operation of the Priest Rapids Project must conform to and comply with all applicable laws, rules, regulations, license conditions or restrictions promulgated by the FERC, the State of Washington or any other governmental agency or entity having jurisdiction over the Priest Rapids Project. The Purchaser shall cooperate and take whatever action is necessary to cooperate fully with the District in meeting such requirements. Obligations of the District contained in this Contract are hereby expressly made subordinate and subject to such compliance.

(b) RCW 54.16.040 contains provisions relating to the District's sale of electric energy. The Parties understand and acknowledge that the District must comply with RCW 54.16.040 to the extent applicable to this Contract and the District's obligations and performance of this Contract are hereby expressly made subordinate and subject to such compliance.

(c) The Purchaser shall ensure that PRPO available to Purchaser under this Contract is not sold, resold, distributed for use or used outside the Pacific Northwest in violation of the Bonneville Project Act, Public Law 75-329, the Pacific Northwest Consumer Power Preference Act, Public Law 88-552, the Regional Act or in contravention of any applicable state or federal law, order, regulation, or policy. If such sales occur in violation of the foregoing, the Purchaser shall reimburse the District for any penalties imposed on and costs incurred by the District as a consequence of such violation. Attached hereto as Exhibit C is a letter from the Bonneville Power Administration regarding this subject.

SECTION 19. HEADINGS

The headings of sections and paragraphs of this Contract are for convenience of reference only and are not intended to restrict, affect or be of any weight in the interpretation or construction of the provisions of such sections and paragraphs.

SECTION 20. ENTIRE AGREEMENT; MODIFICATION; CONFLICT IN PRECEDENCE

This Contract constitutes the entire agreement between the Parties with respect to the subject matter of this Contract, and supersedes all previous communications between the Parties, either verbal or written, with respect to such subject matter. No modifications of this Contract shall be binding upon the Parties unless such modifications are in writing signed by each Party.

SECTION 21. NO PARTNERSHIP OR THIRD PARTY RIGHTS

(a) This Contract shall not be interpreted or construed to create an association, joint venture or partnership between the Parties, or to impose any partnership obligations or liability upon any Party.

(b) This Contract shall not be construed to create rights in or grant remedies to any third party as a beneficiary of this Contract.

SECTION 22. REPRESENTATIONS AND WARRANTIES

Each Party represents and warrants to the other Party that:

(a) It is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation.

(b) The execution, delivery and performance of this Contract are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, or order applicable to it.

(c) This Contract constitutes a legally valid and binding obligation enforceable against it in accordance with its terms, subject to equitable defenses and applicable bankruptcy, insolvency and similar laws affecting creditors' rights generally.

SECTION 23. OPTIONAL AGREEMENT AVAILABLE TO PURCHASER

(a) The Purchaser shall have the option of becoming a joinder to the "1997 Agreement for the Hourly Coordination of Projects on the Mid-Columbia River", pursuant to Section 9(a) of that Agreement.

PUBLIC UTILITY DISTRICT NO. 2
OF GRANT COUNTY, WASHINGTON

By: ________________________________

(SEAL)

President

ATTEST:

Secretary

By: ________________________________
Title:

(SEAL)

ATTEST:

Secretary

EXHIBIT A

DEFINITION OF PRIEST RAPIDS PROJECT

RESOLUTION NO. 390 – DEFINITION OF PRIEST RAPIDS DEVELOPMENT

Section 2(f) of Exhibit 1. "Priest Rapids Development" shall mean those properties and facilities consisting of the Priest Rapids dam, site, reservoir, switchyard and power plant, including all generating facilities associated therewith up to and including the first ten (10) main turbine generator units each with a nameplate rating of approximately 78,850 kilowatts and any additional generating facilities which may be installed as provided for in Section 19 of the Original Power Sales Contract, together with the associated transmission facilities consisting of two 230 KV transmission lines and terminal facilities interconnecting the Priest Rapids switchyard and the Bonneville Power Administration's Midway Substation and an undivided one-half (1/2) interest in the interconnecting facilities between the Priest Rapids switchyard and the Wanapum switchyard.

RESOLUTION NO. 474 - DEFINITION OF WANAPUM DEVELOPMENT

Section 2.2. The District specifies and adopts the plan and system hereinafter set forth for the acquisition, by purchase or condemnation, and construction of the following generation and transmission facilities as a separate utility system of the District constituting the Wanapum Development of the District, to wit:

A. The District shall constrict an electric generating plant and associated facilities on the Columbia River at approximately river mile 415 from the mouth of said river at the Wanapum site on said river, in Grant and Kittitas Counties, Washington, as authorized by the Federal Power Commission License for Project No. 2114, originally issued November 4, 1955, and all amendments thereto; said generating plant to have an installed nameplate rating of approximately 831,250 kilowatts, and said generating plant and associated facilities to include, but not limited to, a concrete gravity dam, a fully enclosed reinforced concrete powerhouse containing ten (10) turbo-generating units with provisions in the intake structure for the installation of six (6) additional turbo-generating units, a reservoir, waterways, fish ladders and other fish protective devices; provisions for future installation of navigation locks; transforming facilities; a switchyard; transmission facilities necessary to connect the powerhouse to the existing transmission facilities of the Priest Rapids Development and to the transmission facilities of the Bonneville Power Administration in the vicinity of said Project; railroad siding, shops, warehouses,

EXHIBIT B

DISTRICT RECOGNIZED HOLIDAYS

HOLIDAY	ACTUAL DATE	DATE OBSERVED
New Year's Day	Thursday, January 1, 2009	Thursday, January 1, 2009
President's Day	Monday, February 16, 2009 (3rd Monday in February)	Monday, February 16, 2009 (3rd Monday in February)
Memorial Day	Monday, May 25, 2009 (Last Monday in May)	Monday, May 25, 2009 (Last Monday in May)
Independence Day	Saturday, July 4, 2009	Friday, July 3, 2009
Labor Day	Monday, September 7, 2009 (1st Monday in September)	Monday, September 7, 2009 (1st Monday in September)
Veterans Day	Wednesday, November 11, 2009	Wednesday, November 11, 2009
Thanksgiving Day	Thursday, November 26, 2009 (4th Thurs. in November)	Thursday, November 26, 2009 (4th Thurs. in November)
Christmas Day	Friday, December 25, 2009	Friday, December 25, 2009

EXHIBIT C
BPA's LETTER REGARDING 5(B)9(C)

Department of Energy

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

POWER BUSINESS LINE

August 9, 2006

In reply refer to: PS-6

Mr. Tim Culbertson, General Manager
Public Utility District No. 2 of Grant County
P.O. Box 878
Ephrata, WA 98823

Dear Mr. Culbertson:

The Bonneville Power Administration (BPA) and Grant County Public Utility District No. 1 (Grant) met on July 26, 2006 to discuss Grant's pending Priest Rapids Development Project market based auction. Grant is preparing for its 2006 Power Auction of the Priest Rapids Project output as a pricing mechanism for the 30 percent Reasonable Portion product sold to Pub. L. 544 parties. The open market auction process is a fairly new mechanism for a utility to make power sales in the region and is Grant's choice for implementing the Federal Energy Regulatory Commission (FERC) order regarding the reasonable portion requirement of Pub. L. 544 in Kootenai Electric Coop. Inc. et al v. Public Utility District No. 2, 82 FERC ¶ 61,112, affirmed in Kootenai Electric Cooperative Inc. v. Federal Energy Regulatory Commission, 192 F.3d 144 (D.C. Cir. 1999). Grant conducted a prior auction which resulted in a sale of Project power to Constellation Energy, Inc. As we discussed at our July 26th meeting, we both would like to ensure compliance of Grant's auction sales with the application of BPA statutes and policy regarding the sale of customer-owned hydroelectric resources under Section 3(d) of Pub. L. 88-552, the Pacific Northwest Consumer Power Preference Act, and section 9(c) of Pub. L. 96-501, the Pacific Northwest Electric Power Planning and Conservation Act. Therefore, BPA wishes to address its understanding reached after our discussion on July 26th as to treatment of these sales and Grant's 2005 auction sale to Constellation.

BPA's Policy on Determining Net Requirements of the Pacific Northwest Utility Customers under Sections 5(b)(1) and 9(c) of the Northwest Power Act (May 2000) addresses the extra-regional sale of regional resources, including output from hydroelectric resources such as the Priest Rapids Project. It is understood by BPA that, based on the above mentioned FERC order, Grant has no right to the power from the Project that is represented by the 30 percent Reasonable Portion and is required to offer this power to participating parties. We also understand that the power offered is part of the Reasonable Portion and is used to set a price for the entire Reasonable Portion sale. As seller, and in order to comply with both the FERC order and BPA's policy and statutes, you have included in your contracts for the sale of this power a provision which states: "The purchaser shall ensure that Priest Rapids Development Output available to Purchaser under this contract is not sold, resold, distributed for use or used outside the Pacific Northwest in violation of the Bonneville Project Act, Public Law 75-329, the Pacific Northwest

Consumer Power Preference Act, Public Law 88-552, the Regional Act or in contravention of any applicable state or Federal law, order regulation or policy." While that provision is a good first step, it does not address the practical consideration of reporting resale information by the purchaser and does not in all instances identify what actions BPA may be required to take under its statutes.

To clarify our mutual responsibilities regarding Grant's auction sales we discussed and agreed upon the following compliance protocol:

1. Grant will continue to include in its open market auction contracts a provision that requires compliance by the purchaser with BPA's policy and statutes governing the sale of non-Federal power, substantially in the form noted above. In the event of resale in violation of that provision, BPA would have recourse against Grant by reduction of BPA's firm power sale (decrement) consistent with BPA's statutes and policy.

2. As the seller, Grant remains responsible for the in-region use of the power when the sale at auction is made to a purchaser that is an entity that does not have a Northwest Power Act section 5(b) contract with BPA, or that does not directly serve retail consumer load in the Region. Grant is responsible for demonstrating the purchaser resold the power to a Northwest load serving investor-owned utility, public or cooperative utility, or direct service industry (DSI) customer with a section 5(b) or 5(d) contract that has a planned load in excess of its planned generation. Customers holding a 5(b) or 5(d) contract, other than those that receive all of their firm power supply from BPA, are assumed to have a planned load in excess of their planned generation.

3. As long as the purchaser's monthly sales of power to the BPA customers identified in 2 above meets or exceeds the amount of firm power bought at auction and delivered for the month, then BPA will consider the resale as used in the Region. Grant will monitor such sales by the purchaser by keeping monthly records of tags, commercial arrangement documents, or FERC website hourly data files, whichever is appropriate. If requested by BPA, Grant will provide this information to BPA 15 days after the end of a month. In the event that such resale by the purchaser does not equal the amount of power purchased at auction in the month, BPA may impose a decrement on its firm power sales in subsequent months to Grant equal to the difference. Grant may have a contractual recourse against the purchaser.

4. If the sale at auction is to the BPA customers identified in 2 above, then BPA will consider the power sold at auction used for load in the Region.

Constellation Sale

BPA's statutes and 9(c) policy require BPA to make certain determinations regarding the effect of potential sales of power outside the region of non-Federal power resources, or exports upon its firm power requirements obligations to provide service to its customers. BPA is only allowed to

replace such power exported with Federal power that is otherwise surplus to BPA's firm power obligations. These determinations are factually based and can result in BPA reducing or decrementing its firm power obligations to the seller. In response to BPA's April 27, 2006, letter to Grant, Grant has supplied BPA data files that show certain sales made at the Mid-Columbia Hub by Constellation, the 2005 purchaser of power auctioned by Grant as the 6 percent Priest Rapids Project output. These files demonstrate Constellation has sold the 2005 auction power to several Northwest load serving utilities, or cooperatives that have 5(b) or 5(d) contracts. Further, for the period of this 2005 auction, BPA's regional planning document, the Whitebook, as updated, showed both BPA and the region in a surplus power condition having firm resources that exceed firm loads for that planning year (2005). Therefore, BPA finds that Grant's sale to Constellation and Constellation's resale of power from the 2005 auction complies with BPA's 9(c) policy. BPA finds no need to decrement or reduce Grant's block purchase from BPA and Grant will not be decremented.

Thank you for taking the time to meet with us and establishing the compliance protocol we have both agreed to, as described above. I wish you success on your upcoming auction and appreciate your patience in resolving this issue.

Sincerely,

/s/ Mark Gendron

Mark Gendron
Vice President
Requirements Marketing

APPENDIX D

BPA Programmatic Conservation Resources

Documentation of the Annual Amounts of Conservation Resources Available

AND

Documentation of Acquisition Cost
Annual Amounts Expensed and Amounts Capitalized and Financed

Section 7(b)(2) Rate Test Study and Documentation

WP-10 Initial Rate Proposal

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	A	B	C	D	E	F	G	H	I	J	K	L	M
1					**BPA's 2010 Wholesale Power Rate Case**								
2					**BPA Programmatic Conservation - Historical Savings and Expenditures FYs 1982-2007 - Total Gross Amounts**								
3					**ConMod, C&RD, and Market Transformation aMW Savings and Expenditures Before Adjustments**								
5					**$ Millions of Dollars[1]**								
6													**(C)**
7			**(D) - (C)**	**From (C)**	**(D)**		**(A)**					**(B)**	**(A) + (B)**
8					**Annual**				**BPA Bonds Issued**				**Total**
9		**Conser.**	**Amount**	**Amount**	**Expenditures[3]**	**Amort.**	**BPA Annual**		**Bond**			**Third-Party**	**Capitalized/**
10		**Savings**	**Revenue**	**Debt**	**Per**	**Period**	**Conservation**		**Principal**	**Bond**		**Financed**	**Debt Financed**
11		**aMW[2,]**	**Expended[3,4]**	**Financed[7]**	**"Red Book"**	**Years**	**Capitalized[4]**		**Amount[5]**	**Term[5]**		**Conser.[6]**	**Conservation[7]**
12													
13	1982 Conser.	32.4	4.974	61.940	66.914	20	61.940					0.000	61.940
14	1983 Conser.	68.6	2.907	204.092	206.999	20	204.092		140.0	20		0.000	204.092
15	1984 Conser.	16.6	8.311	66.783	75.094	20	66.783		150.0	20		0.000	66.783
16	1985 Conser.	17.0	24.680	103.067	127.747	20	103.067		50.0	5		0.000	103.067
17	1986 Conser.	23.5	5.256	99.743	104.999	20	97.618		50.0	10		2.125	99.743
18									50.0	5			0.000
19	1987 Conser.	19.7	3.928	71.631	75.559	20	67.381		75.0	20		4.250	71.631
20									50.0	5			0.000
21	1988 Conser.	53.2	8.535	58.570	67.105	20	54.320		90.0	20		4.250	58.570
22	1989 Conser.	51.7	17.643	46.069	63.712	20	41.819		40.0	20		4.250	46.069
23	1990 Conser.	38.1	41.859	36.220	78.079	20	34.095					2.125	36.220
24	1991 Conser.	19.0	43.811	45.714	89.525	20	45.714					0.000	45.714
25	1992 Conser.	37.4	68.496	62.151	130.647	20	62.151		100.0	15		0.000	62.151
26									50.0	20			0.000
27	1993 Conser.	59.6	59.432	96.717	156.149	20	96.717		90.0	20		0.000	96.717
28	1994 Conser.	51.3	58.812	121.242	180.054	20	115.030		50.0	20		6.212	121.242
29									50.0	4			0.000
30	1995 Conser.	65.9	50.702	85.252	135.954	20	72.428		85.0	20		12.824	85.252
31	1996 Conser.	56.3	53.532	52.274	105.806	20	39.450		30.0	15		12.824	52.274
32	1997 Conser.	54.7	28.023	32.953	60.976	20	20.329		40.0	20		12.624	32.953
33	1998 Conser.	33.4	32.546	26.331	58.877	20	14.308					12.023	26.331
34	1999 Conser.	33.1	20.937	19.728	40.665	20	13.716					6.012	19.728
35	2000 Conser.	18.2	15.377	0.347	15.724	20	0.347		32.0	3		0.000	0.347
36	2001 Conser.	30.9	29.148	0.057	29.205	20	0.057					0.000	0.057
37	2002 Conser.	61.0	57.053	28.227	85.280	10	28.227		40.0	3		0.000	28.227
38	2003 Conser.	53.8	58.725	22.900	81.625	9	22.900					0.000	22.900
39	2004 Conser.	51.7	48.573	19.431	68.004	8	19.431		30.0	4		0.000	19.431
40	Adjustments	-1.9											
41	**TOTALS 1982-2004**	945.2	743.260	1,361.439	2,104.699		1,281.920		1,292.0			79.5	1,361.439
43	2005 Conser.	38.0	47.054	14.750	61.804	7	14.750					0.000	14.750
44	2006 Conser.	48.5	47.750	14.970	62.720	6	14.970		20.0	3		0.000	14.970
45	2007 Conser.	58.1	38.860	10.725	49.585	5	10.725		20.0	3		0.000	10.725
46	**TOTALS 2005-2007**	144.6	133.664	40.445	174.109		40.445		40.000			0.000	40.445
48	**TOTALS 1982-2007**	1,089.8	876.924	1,401.884	2,278.808		1,322.365		1,332.000			79.500	1,401.884
50					Page 1 of 2								

BPA's 2010 Wholesale Power Rate Case
BPA Programmatic Conservation - Historical Savings and Expenditures
Gross Cost Amounts Before Adjustments

Notes to Worksheet:

1. Dollar costs are in nominal dollars associated with the year of expenditure.

2. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts for the years 1982-2004 were obtained from the 2004 Conservation Resource Energy Data, "The Red Book" (http://www.bpa.gov/Energy/N/Reports/publications/pdf/2004_red_book.pdf). The annual savings totals for years 1982-2004 were based on Tables A and B using the sub-sector line amounts. The 2004 savings amounts attributable to building codes, market transformation efforts, ConMod, and C&RD are included in the savings totals. See the spread sheet titled "Total BPA Historical Programatic Conservation - Gross Amounts." The information in the 2004 Red Book provided greater detail than the 2005 edition for the years 1982-1999. The amounts in the table were updated and reconciled to the February 2005 Red Book addition (http://www.bpa.gov/Energy/N/reports/publications/pdf/fy05_red_book.pdf) The annual savings and expenditure amounts for the years 2005-2007 were obtained from the 2007 Red Book, (http://www.bpa.gov/Energy/N/Reports/publications/pdf/RED_BOOK_FY07_Final.pdf).

3. Total Annual Expenditures for the years 1982-2004 are based on the "Total Cumulative Cost" column, Table D of the 2005 version of the "Red Book." The total expenditures include overhead loadings and indirect costs. Expenditures for building codes, market transformation, ConMod, and C&RD are included in the totals. In addition the amount of conservation investments funded with third-party debt are included in the totals. Annual expenditures for the years 2005-2007 are based on the "Total Incremental Cost" row, Table D of the 2007 version of the "Red Book." The total expenditures include overhead loadings and indirect costs. Expenditures for market transformation, C&RD, CRC, Energy Web Costs, and Conservation Support Costs are separately identified.

4. The annual amount capitalized is based on the additions to Annual Plant in Service based on the 2007 Supplemental Revenue Requirement Study Documentation WP-10-E-BPA-10, Volume 1, Chapter 4, Tables 4M, 4N, and 4o. This number is consistent with the information in BPA's annual reports after subtracting amortization of prior year investments.

5. The amount of conservation bonds issued and the term of the bonds is based on the Revenue Requirement Study Documentation WP-10-E-BPA-10 Volume 1, Chapter 7, Table 7G.

6. BPA has agreed to pay the debt service for Conservation and Renewable Energy System (CARES) a joint operating agency (JOA) of the State of Washington, Emerald Public Utility District, City of Tacoma (Tacoma Power), and Eugene Water and Electric Board. The amounts in the column Third-Party Financed Conservation represent the original issue amount (principle) of bonds to finance conservation projects.

7. Total Capitalized/Debt Financed Conservation is comprised of BPA capitalized expenditures that were financed with U.S. Treasury Bonds and the conservation that is capitalized under Nonfederal Projects in BPA's financial statements which consists of third-party funded conservation as outlined in Note 6 above.

BPA's 2010 Wholesale Power Rate Case

Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]

	1982	1983	1984	1985	1986	1987	1988
Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
Adj.	0.0	(0.6)	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.0	48.9	10.6	9.0	9.3	5.0	5.0
Commercial - C&RD	2.5	20.8	6.4	8.0	12.4	8.0	1.0
Adj.	(0.1)	(1.1)	(0.4)	(0.4)	(0.7)	(0.4)	(0.1)
Sub TOTAL	2.4	19.7	6.0	7.6	11.7	7.6	0.9
Industrial - C&RD	0.0	0.0	0.0	0.0	0.4	0.9	4.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)
Sub TOTAL	0.0	0.0	0.0	0.0	0.4	0.9	4.1
Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
Adj.	0.0	(0.5)	(0.5)	(0.9)	(0.9)	(1.3)	(1.4)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Building Codes	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Con/Mod	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	32.5	70.8	17.5	18.3	25.1	21.4	54.9
Adjustments	(0.1)	(2.2)	(0.9)	(1.3)	(1.6)	(1.7)	(1.7)
Net Annual Amt.	32.4	68.6	16.6	17.0	23.5	19.7	53.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

BPA's 2010 Wholesale Power Rate Case

Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]

	1989	1990	1991	1992	1993	1994	Subtotal 1982-1994
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.0
Commercial - C&RD	0.9	1.0	1.0	5.0	11.4	14.1	92.5
Adj.	0.0	(0.1)	(0.1)	(0.3)	(0.6)	(0.9)	(5.2)
Sub TOTAL	0.9	0.9	0.9	4.7	10.8	13.2	87.3
Industrial - C&RD	6.7	2.2	6.3	6.1	15.2	11.3	53.4
Adj.	(0.4)	(0.1)	(0.3)	(0.3)	(0.9)	(0.6)	(2.8)
Sub TOTAL	6.3	2.1	6.0	5.8	14.3	10.7	50.6
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	(0.1)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(6.2)
Sub TOTAL	1.3	0.1	1.1	0.8	1.5	1.4	6.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Con/Mod	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	52.2	38.3	19.5	38.1	61.3	53.0	502.9
Adjustments	(0.5)	(0.2)	(0.5)	(0.7)	(1.7)	(1.7)	(14.8)
Net Annual Amt.	51.7	38.1	19.0	37.4	59.6	51.3	488.1

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

BPA's 2010 Wholesale Power Rate Case

Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]

	1995	1996	1997	1998	1999	2000
Residential - C&RD	3.4	1.4	0.6	0.7	0.6	0.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3
Commercial - C&RD	9.3	5.3	4.8	6.8	0.5	0.0
Adj.	(0.5)	(0.2)	(0.2)	(0.3)	0.0	0.0
Sub TOTAL	8.8	5.1	4.6	6.5	0.5	0.0
Industrial - C&RD	18.2	11.8	6.7	0.2	0.2	0.0
Adj.	(1.1)	(0.6)	(0.4)	0.0	0.0	0.0
Sub TOTAL	17.1	11.2	6.3	0.2	0.2	0.0
Agriculture - C&RD	1.8	0.6	0.0	0.0	0.0	0.0
Adj.	(0.2)	(0.2)	0.0	0.0	0.0	0.0
Sub TOTAL	1.6	0.4	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	20.1	23.6	27.9	12.9	13.4	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0
Building Codes	14.9	14.6	15.3	13.1	14.4	12.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9
Con/Mod	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	4.0	5.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	4.0	5.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	67.7	57.3	55.3	33.7	33.1	18.2
Adjustments	(1.8)	(1.0)	(0.6)	(0.3)	0.0	0.0
Net Annual Amt.	65.9	56.3	54.7	33.4	33.1	18.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

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	Y	Z	AA	AB	AC	AD	AE
1	**BPA's 2010 Wholesale Power Rate Case**						
2	**Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]**						
3						Other	FY 1982-
4		2001	2002	2003	2004	Adjust's	FY 2004
6	Residential - C&RD	2.8	7.3	1.2	9.6		200.5
7	Adj.	(0.5)	(1.3)	(0.2)	0.0	0.2	(2.4)
8	Sub TOTAL	2.3	6.0	1.0	9.6	0.2	198.1
10	Commercial - C&RD	1.7	12.6	13.6	10.4		157.5
11	Adj.	0.0	0.2	0.2	0.0	(1.6)	(7.6)
12	Sub TOTAL	1.7	12.8	13.8	10.4	(1.6)	149.9
14	Industrial - C&RD	0.0	3.5	5.1	3.5		102.6
15	Adj.	0.0	(0.2)	0.0	0.0	(0.5)	(5.6)
16	Sub TOTAL	0.0	3.3	5.1	3.5	(0.5)	97.0
18	Agriculture - C&RD	0.0	0.0	0.0	0.0		14.8
19	Adj.	0.0	0.0	0.0	0.0		(6.6)
20	Sub TOTAL	0.0	0.0	0.0	0.0		8.2
22	Multi-Sector - C&RD	0.0	0.0	0.0	0.0		104.2
23	Adj.	0.0	0.0	0.0	0.0	0.0	0.0
24	Sub TOTAL	0.0	0.0	0.0	0.0		104.2
26	Building Codes	12.4	13.0	4.2	3.9		188.5
27	Adj.	0.0	0.0	0.0	0.0	0.0	0.0
28	Sub TOTAL	12.4	13.0	4.2	3.9		188.5
30	Con/Mod	0.0	0.0	0.0	0.0		95.9
31	Adj.	0.0	0.0	0.0	0.0	0.0	0.0
32	Sub TOTAL	0.0	0.0	0.0	0.0		95.9
34	Market Trans.	7.0	12.0	16.0	14.0		58.0
35	Adj.	0.0	0.0	0.0	0.0	0.0	0.0
36	Sub TOTAL	7.0	12.0	16.0	14.0		58.0
38	**C&RD**	9.6	17.7	17.5	13.1		57.9
39	Adj.	(2.1)	(3.8)	(3.8)	(2.8)	(5.2)	(17.7)
40	Sub TOTAL	7.5	13.9	13.7	10.3	(5.2)	40.2
41							
42	**Totals before Adj.**	33.5	66.1	57.6	54.5		979.9
43	**Adjustments**	(2.6)	(5.1)	(3.8)	(2.8)	(1.9)	(34.7)
44	**Net Annual Amt.**	30.9	61.0	53.8	51.7	(1.9)	945.2
45							
46			Total Above				945.2
47			Less ConMod				(95.9)
48			June 2005 Red Book Table A page 5				849.3
49							
50			Page 4 of 5				
52							

BPA's 2010 Wholesale Power Rate Case

Total BPA Historical Programmatic Conservation - Gross Savings Amounts[1]

	2005	2006	2007	Other Adjust's	FY 2005-FY 2007
Residential	10.5	10.7	13.4		34.6
C&RD/CRC Adj.	(8.5)	(5.0)	(6.9)		(20.4)
Sub TOTAL	2.0	5.7	6.5		14.2
Commercial	9.5	14.6	9.4		33.5
C&RD/CRC Adj.	(0.4)	(0.8)	(3.2)		(4.4)
Sub TOTAL	9.1	13.8	6.2		29.1
Industrial	3.4	8.2	6.2		17.8
C&RD/CRC Adj.	(0.6)	(2.6)	(5.3)		(8.5)
Sub TOTAL	2.8	5.6	0.9		9.3
Agriculture	0.1	0.5	4.2		4.8
C&RD/CRC Adj.	(0.1)	(0.1)	(2.9)		(3.1)
Sub TOTAL	0.0	0.4	1.3		1.7
Multi-Sector	1.9	0.2	0.1		2.2
C&RD/CRC Adj.	0.0	0.0	0.0		0.0
Sub TOTAL	1.9	0.2	0.1		2.2
Market Trans.	12.7	14.2	24.9		51.8
Adj.	0.0	(0.6)	(3.6)		(4.2)
Sub TOTAL	12.7	13.6	21.3		47.6
C&RD and CRC	9.6	9.1	21.9		40.6
Adj.	(0.1)	0.1	0.0		0.0
Sub TOTAL	9.5	9.2	21.9		40.6
Totals before Adj.	38.1	48.4	58.2		144.7
Adjustments	(0.1)	0.1	(5.6)		(5.6)
Net Annual Amt.	38.0	48.5	52.6		139.1

Adjustment Detail:			
Utility Self Funded HWM:			
Residential			(1.37)
Commercial			(0.96)
Industrial			(0.63)
Market Trans.			(2.54)
Rounding	(0.10)	0.10	(0.10)
Totals	(0.10)	0.10	(5.60)

	A	B	C	D	E	F	G	H
1	**BPA's 2010 Wholesale Power Rate Case**							
2	**BPA 1982-2004 NET Historical Programmatic Conservation Savings - After Adjustments[1]**							
3								
4								
5								
6		1982	1983	1984	1985	1986	1987	1988
7								
8	Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
9	Adj.	0.0	(0.6)	0.0	0.0	0.0	0.0	0.0
10	Sub TOTAL	30.0	48.9	10.6	9.0	9.3	5.0	5.0
12	Commercial - C&RD	2.5	20.8	6.4	8.0	12.4	8.0	1.0
13	Adj.	(0.1)	(1.1)	(0.4)	(0.4)	(0.7)	(0.4)	(0.1)
14	Sub TOTAL	2.4	19.7	6.0	7.6	11.7	7.6	0.9
16	Industrial - C&RD	0.0	0.0	0.0	0.0	0.4	0.9	4.3
17	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)
18	Sub TOTAL	0.0	0.0	0.0	0.0	0.4	0.9	4.1
20	Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
21	Adj.	0.0	(0.5)	(0.5)	(0.9)	(0.9)	(1.3)	(1.4)
22	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
28	Building Codes[4]	0.0	0.0	0.0	0.4	2.1	3.7	5.6
29	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30	Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
32	Con/Mod[5]	0.0	0.0	0.0	0.0	0.0	2.5	37.6
33	Adj.	0.0	0.0	0.0	0.0	0.0	(2.5)	(37.6)
34	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
36	Market Transformation[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
41	Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
42	Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
44	**Totals before Adj.**	32.5	70.8	17.5	18.3	25.1	21.4	54.9
45	**Adjustments**	(0.1)	(2.2)	(0.9)	(1.3)	(1.6)	(4.2)	(39.3)
46	**Net Annual Amt.**	32.4	68.6	16.6	17.0	23.5	17.2	15.6
48	**Note 1** - The aMWs of savings acquired and the annual expenditures are gross amounts							
49	with no adjustments for degradation of measures over time. The annual savings amounts							
50	were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."							
51								
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55		Page 1 of 8						
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BPA's 2010 Wholesale Power Rate Case

BPA 1982-2004 NET Historical Programmatic Conservation Savings - After Adjustments[1]

	1989	1990	1991	1992	1993	1994	1982-1994 Totals
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.0
Commercial - C&RD	0.9	1.0	1.0	5.0	11.4	14.1	92.5
Adj.	0.0	(0.1)	(0.1)	(0.3)	(0.6)	(0.9)	(5.2)
Sub TOTAL	0.9	0.9	0.9	4.7	10.8	13.2	87.3
Industrial - C&RD	6.7	2.2	6.3	6.1	15.2	11.3	53.4
Adj.	(0.4)	(0.1)	(0.3)	(0.3)	(0.9)	(0.6)	(2.8)
Sub TOTAL	6.3	2.1	6.0	5.8	14.3	10.7	50.6
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	(0.1)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(6.2)
Sub TOTAL	1.3	0.1	1.1	0.8	1.5	1.4	6.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes[4]	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Con/Mod[5]	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Adj.	(30.9)	(24.9)	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Transformation[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	52.2	38.3	19.5	38.1	61.3	53.0	502.9
Adjustments	(31.4)	(25.1)	(0.5)	(0.7)	(1.7)	(1.7)	(110.7)
Net Annual Amt.	20.8	13.2	19.0	37.4	59.6	51.3	392.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's 2010 Wholesale Power Rate Case

BPA 1982-2004 NET Historical Programmatic Conservation Savings - After Adjustments[1]

Q	R	S	T	U	V	W
	1995	1996	1997	1998	1999	2000
Residential less C&RD	3.4	1.4	0.6	0.7	0.6	0.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3
Commercial less C&RD	9.3	5.3	4.8	6.8	0.5	0.0
Adj.	(0.5)	(0.2)	(0.2)	(0.3)	0.0	0.0
Sub TOTAL	8.8	5.1	4.6	6.5	0.5	0.0
Industrial less C&RD	18.2	11.8	6.7	0.2	0.2	0.0
Adj.	(1.1)	(0.6)	(0.4)	0.0	0.0	0.0
Sub TOTAL	17.1	11.2	6.3	0.2	0.2	0.0
Agriculture less C&RD	1.8	0.6	0.0	0.0	0.0	0.0
Adj.	(0.2)	(0.2)	0.0	0.0	0.0	0.0
Sub TOTAL	1.6	0.4	0.0	0.0	0.0	0.0
Multi-Sector less C&RD	20.1	23.6	27.9	12.9	13.4	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0
Building Codes[4]	14.9	14.6	15.3	13.1	14.4	12.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9
Con/Mod[5]	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Market Transformation[3]	0.0				4.0	5.0
Adj.	0.0	0.0	0.0	0.0	(2.7)	(3.4)
Sub TOTAL	0.0	0.0	0.0	0.0	1.3	1.6
C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	67.7	57.3	55.3	33.7	33.1	18.2
Adjustments	(1.8)	(1.0)	(0.6)	(0.3)	(2.7)	(3.4)
Net Annual Amt.	65.9	56.3	54.7	33.4	30.4	14.8

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's 2010 Wholesale Power Rate Case

BPA 1982-2004 NET Historical Programmatic Conservation Savings - After Adjustments[1]

	2001	2002	2003	2004	Other Adjust's	TOTALS FY 1982- FY 2004
Residential less C&RD	2.8	7.3	1.2	9.6		200.5
Adj.	(0.5)	(1.3)	(0.2)	0.0	0.2	(2.4)
Sub TOTAL	2.3	6.0	1.0	9.6		198.1
Commercial less C&RD	1.7	12.6	13.6	10.4		157.5
Adj.	0.0	0.2	0.2	0.0	(1.6)	(7.6)
Sub TOTAL	1.7	12.8	13.8	10.4		149.9
Industrial less C&RD	0.0	3.5	5.1	3.5		102.6
Adj.	0.0	(0.2)	0.0	0.0	(0.5)	(5.6)
Sub TOTAL	0.0	3.3	5.1	3.5		97.0
Agriculture less C&RD	0.0	0.0	0.0	0.0		14.8
Adj.	0.0	0.0	0.0	0.0	0.0	(6.6)
Sub TOTAL	0.0	0.0	0.0	0.0		8.2
Multi-Sector less C&RD	0.0	0.0	0.0	0.0		104.2
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0		104.2
Building Codes[4]	12.4	13.0	4.2	3.9		188.5
Adj.	0.0	(13.0)	(4.2)	(3.9)	0.0	(21.1)
Sub TOTAL	12.4	0.0	0.0	0.0		167.4
Con/Mod[5]	0.0	0.0	0.0	0.0		95.9
Adj.	0.0	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0		0.0
Market Transformation[3]	7.0	12.0	16.0	14.0		58.0
Adj.	(4.7)	(8.0)	(10.7)	(9.4)	0.0	(38.9)
Sub TOTAL	2.3	4.0	5.3	4.6		19.1
C&RD[2]	7.5	13.9	13.7	10.3		45.4
Adj.	(7.5)	(13.9)	(13.7)	(10.3)	0.0	(45.4)
Sub TOTAL	0.0	0.0	0.0	0.0		0.0
Totals before Adj.	31.4	62.3	53.8	51.7		967.4
Adjustments[6]	(12.7)	(36.2)	(28.6)	(23.6)	3.3	(218.3)
Net Annual Amt.	18.7	26.1	25.2	28.1	3.3	749.1
		Total Above				749.1
		Plus C&RD Reductions				45.4
		Plus Bldg. Code Reductions				21.1
		Difference in C&RD				(5.2)
		Plus Market Transformation Reductions				38.9
		2005 Red Book Table A page 5				849.3

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	AG	AH	AI	AJ	AK	AL	AM
1	**BPA's 2010 Wholesale Power Rate Case**						
2	**BPA 1982-2004 NET Historical Programmatic Conservation Savings - After Adjustments[1]**						
3					Other		FY 2005-
4		2005	2006	2007	Adjust's		FY 2007
5							
6							
7							
8	Residential less C&RD	2.0	5.7	5.1			12.8
9	Adj.						
10	Sub TOTAL	2.0	5.7	5.1			12.8
11							
12	Commercial less C&RD	9.1	13.8	5.2			28.1
13	Adj.						
14	Sub TOTAL	9.1	13.8	5.2			28.1
15							
16	Industrial less C&RD	2.8	5.6	0.3			8.7
17	Adj.						
18	Sub TOTAL	2.8	5.6	0.3			8.7
19							
20	Agriculture less C&RD	0.0	0.4	1.3			1.7
21	Adj.						
22	Sub TOTAL	0.0	0.4	1.3			1.7
23							
24	Multi-Sector less C&RD	1.9	0.2	0.1			2.2
25	Adj.						
26	Sub TOTAL	1.9	0.2	0.1			2.2
27							
28	Building Codes[4]	0.0	0.0	0.0			0.0
29	Adj.	0.0	0.0	0.0			0.0
30	Sub TOTAL	0.0	0.0	0.0			0.0
31							
32	Con/Mod[5]	0.0	0.0	0.0			0.0
33	Adj.	0.0	0.0	0.0			0.0
34	Sub TOTAL	0.0	0.0	0.0			0.0
35							
36	Market Transformation[3]	12.7	13.6	18.8			45.1
37	Adj.	(8.5)	(9.1)	(12.6)			(30.2)
38	Sub TOTAL	4.2	4.5	6.2			14.9
39							
40	C&RD and CRC[2]	9.5	9.2	21.9			40.6
41	Adj.	(9.5)	(9.2)	(11.6)			(30.3)
42	Sub TOTAL	0.0	0.0	10.3			10.3
43							
44	**Totals before Adj.**	38.0	48.5	52.7			139.2
45	**Adjustments[7]**	(18.0)	(18.3)	(24.2)	0.0		(60.5)
46	**Net Annual Amount 7(b)(2)**	20.0	30.2	28.5			78.7
47							
48	Adjustment Detail:						
49	C&RD / CRC Reductions	9.5	9.2	11.6			30.3
50	Market Trans. Reductions	8.5	9.1	12.6			30.2
51	Utility Self Funded HWM - See Page D-7 for detail			5.5			5.5
52	Rounding			(0.1)			(0.1)
53	2007 Red Book Table B page 8	38.0	48.5	58.1			144.6
54							
55		Page 5 of 8					
56							
57							
58							

BPA 1982-2007 NET Historical Programmatic Conservation Savings - After Adjustments[1]
NET BPA Conservation Program Savings - Section 7(b)(2) Amounts

Notes Concerning Conservation Savings Adjustments:

1. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts for 1982-2003 were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book." The annual saving totals for years 1982-1999 were based on Table B2 , pages 7-8, using the sub-sector line amounts. The annual savings for the years 2000-2003 are based on Table B1, page 6 of The 2004 Red Book, using the amounts for ConAug by sector plus the low income residential weatherization amounts. The information in the 2004 Red Book provided greater detail than the 2005 edition of the Red Book concerning the amount of conservation savings for the years 1982-1999. The final results in the tables were updated and reconciled to the February 2005 Red Book. Saving amounts attributable to ConMod, and C&RD have been totally removed from the cumulative totals for FY's 1982-2006. See the additional notes below on adjustments made to the Red Book's gross amounts. The annual savings amounts for 2005-2007 were obtained from the 2007 Conservation Resource Energy Data, "The Red Book." The annual saving totals for years 2005-2007 were based on Table B , page 8, using the sub-sector line amounts.

2. Savings and expenditures attributable to C&RD were removed in total for the years prior to 2007 because there was not adequate compliance efforts in place during those years to have sufficient certainty that the savings were achieved. BPA's post -2006 Conservation Program has provided additional compliance requirements surrounding the CRC program to help ensure the achievement of conservation savings associated with the granting of CRC credits. The majority of CRC expenditures are received by non-load following utilities that purchase the Slice and Flat-Block power products. The Administrator's load obligations to these utilities has not been reduced, (contract power amounts have not been decremented for the conservation savings) thus BPA will not receive a direct benefit from CRC expenditures associated with non-load following customers during the Section 7(b)(2) rate test period. BPA does receive a direct benefit from load following customers associated with the conservation that occurs in those utility's service territories. Because of the additional controls surrounding the achievement of conservation savings during the post 2006 time period, and because BPA does receive a direct benefit from expenditures that occur in load following utility service territories, the portion of the CRC savings attributable to load following utilities has been included in the Section 7(b)(2) resource stack for FY 2007. The reduction in conservation savings attributable to the CRC program available to the Section 7(b)(2) resource stack for FY 2007 was based on the projected amount of non-load following loads.

Load following BPA customer Total Retail Loads are forecasted at 4,292 aMW for FY 2009, non-load following loads are forecasted at 4,821, for a total of 9,113aMW (Total Retail Loads). Non-load following loads represent 53% of total forecasted BPA loads and load following loads represent 47% of BPA's total loads. Thus 53% of the saving attributable to FY 2007 CRC efforts will be removed from the 7(b)(2) resource stack. This net amount after adjustment will remain fixed for subsequent rate cases, and will not change due to future changes in the relationship of BPA's load following and non-load following loads.

Notes Concerning Conservation Savings Adjustments Continued:

3. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1999-2008 time frame. BPA plans to continue funding NEEA's efforts through the 2015 time period at the same level of support. BPA's "Red Book" claims one half of the regional savings attributable to NEEA's efforts commensurate with it's level of funding. The expenditures that BPA pays NEEA only has a partial impact on reducing the Administrator's load obligations. The amount of load reduction from these expenditures is calculated as follows:

BPA Customer's Forecasted FY 2009 Total Retail Loads:

Load Following Customers	4,292.0	aMW	47%
Non-Load Following Customers	4,821.0	aMW	53%
	9,113.0	**aMW**	**100%**
Forecasted FY 2009 Regional Loads (No DSIs)	21,205.0	aMW	100%
BPA's Forecasted FY 2009 Loads (No DSIs)	7,406.0	aMW	35%

DSI loads were excluded from both amounts because market transformation efforts do not impact DSI loads. Of the total BPA forecasted loads of 7,406aMW (35% of total regional loads), there is no reduction in contracted power purchases for BPA's non-load following customers. No reduction of purchased power amounts in slice and block power purchase contracts due to NEEA savings were made during this period of time, and no decrements are forecasted for the 2010-2015 time period. For every megawatt of conservation savings that is achieved by NEEA's market transformation efforts, BPA's load obligations are reduced by approximately 16.45 percent (35% x 47%). Because the Red Book only claims half of the NEEA savings it is necessary to adjust the calculation below that is based on total regional loads by doubling the final savings amount. The adjustment necessary to reflect just the direct benefit of savings to BPA loads is to reduce the savings in the table by sixty-seven percent (67%). This percentage is derived by doubling the 16.45% above and subtracting this total from 100% of the gross savings contained in the Red Book (100% -(2 x 16.45%)) = 67%. This net amount after adjustment will remain fixed for subsequent rate cases, and will not change due to future changes in the relationship of BPA's load following and non-load following loads.

4. Adjustments were made to remove savings attributable to building codes for the years after 2001. BPA's Conservation Program staff are of the opinion that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should have a high degree of assurance that the conservation savings would be able to reduce 7(b)(2) Case loads.

BPA 1982-2007 NET Historical Programmatic Conservation Savings - After Adjustments[1]
NET BPA Conservation Program Savings - Section 7(b)(2) Amounts

Notes Concerning Conservation Savings Adjustments Continued:

5. As previously noted in the table of Gross Conservation Savings, The 2005 Red Book totals have excluded the savings from ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating, and since the amount of load that BPA might serve is not known with a high degree of certainty, the conservation savings from these past investments is not available to reduce loads in the 2010-2015 time period of the 7(b)(2) rate test. The expenditures for ConMod investments were left in the 2005 Red Book to meet the Red Book's objective of accounting for all conservation expenditures. The expenditures for past ConMod investments were removed from the expenditure totals that were included in the 7(b)(2) resource stack.

6. Starting in FY 2007 the Red Book started reporting utility Self-Funded Conservation Savings in the conservation savings totals. These savings were undertaken by BPA's customers without BPA funding. No expenditures for these savings were reported in the Red Book. These savings for FY 2007 totaling 5.5 aMW were removed from the totals to arrive at BPA's conservation efforts that should be included in the 7(b)(2) resource stack.

7. The following adjustments were made to the 2005 Red Book's conservation savings for the years 1982-2004:

Building Code Savings	21.1	aMW
Market Transformation Savings	38.9	aMW
C&RD Savings	40.2	aMW
	100.2	**aMW**

The total conservation savings per the Red Book for FY1982-2004 was 849.3 aMW after netting out 95.9aMW of ConMod savings. The total savings included in the 7(b)(2) resource stack for those years was 749.1aMW after subtracting the above adjustments totaling 100.2 aMW.

8. The following adjustments were made to the 2007 Red Book's conservation savings for the years 2005-2007:

Utility Self Funded HWM	5.5	aMW
Market Transformation Savings	30.2	aMW
C&RD and CRC Savings	30.3	aMW
	66.0	**aMW**

The total conservation savings per the Red Book for FY2005-2007 was 144.7 aMW, the total savings included in the 7(b)(2) resource stack for those years was 78.7 aMW.

BPA's 2010 Wholesale Power Rate Case

Total Historical Conservation Expenditures -1982-2007, Per Red Book, Adjusted for Plant Accounting Capitalized Conservation Expenditures

($000) [1]

A	B	C	D	E	F	G	H	J	K	L	M	N	O	P	R	S
		CAPITALIZED COSTS						EXPENSED CONSERVATION COSTS								
				BPA CAPITALIZED COSTS												
Year	Total Incremental Yearly Costs Table D Red Book	Total Capitalized Costs	Third Party Financing Costs/ Original Issue Amount	Capitalized Conser. Costs	ConAcq Costs	ConAug Costs	Legacy Conser. Costs	Total Expense Costs	Support Costs[2]	Market Transform. Costs[5]	Con/Mod Costs[3]	C&RD CRC Total Costs[4]	Energy WEB & New Initiatives	Other Conser. Expense Costs	TOTAL CONSER. COSTS	Gross Conser. Savings per Red Book
1982	66,914	61,940	0	61,940		0	61,940	4,974	4,974	0	0	0	0	0	66,914	32.4
1983	206,999	204,092	0	204,092		0	204,092	2,907	2,907	0	0	0	0	0	206,999	68.6
1984	75,094	66,783	0	66,783		0	66,783	8,311	7,589	0	0	0	0	722	75,094	16.6
1985	127,747	103,067	0	103,067		0	103,067	24,680	20,232	0	0	0	0	4,448	127,747	17.0
1986	104,999	99,743	2,125	97,618		0	97,618	5,256	5,256	0	0	0	0	0	104,999	23.5
1987	75,559	71,631	4,250	67,381		0	67,381	3,928	3,928	0	0	0	0	0	75,559	19.7
1988	67,105	58,570	4,250	54,320		0	54,320	8,535	6,654	0	1,881	0	0	0	67,105	53.2
1989	63,712	46,069	4,250	41,819		0	41,819	17,643	12,917	0	4,726	0	0	0	63,712	51.7
1990	78,079	36,220	2,125	34,095		0	34,095	41,859	5,359	0	6,063	0	0	30,437	78,079	38.1
1991	89,525	45,714	0	45,714		0	45,714	43,811	5,106	0	6,254	0	0	32,451	89,525	19.0
1992	130,647	62,151	0	62,151		0	62,151	68,496	4,134	0	4,553	0	0	59,809	130,647	37.4
1993	156,149	96,717	0	96,717		0	96,717	59,432	8,119	0	4,179	0	0	47,134	156,149	59.6
1994	180,054	121,242	6,212	115,030		0	115,030	58,812	8,210	0	6,462	0	0	44,140	180,054	51.3
1995	135,954	85,252	12,824	72,428		0	72,428	50,702	7,915	0	4,045	0	0	38,742	135,954	65.9
1996	105,806	52,274	12,824	39,450		0	39,450	53,532	7,863	0	4,595	0	0	41,074	105,806	56.3
1997	60,976	32,953	12,624	20,329		0	20,329	28,023	14,800	3,900	2,744	0	0	6,579	60,976	54.7
1998	58,877	26,331	12,023	14,308		0	14,308	32,546	12,200	12,000	2,358	0	0	5,988	58,877	33.4
1999	40,665	19,728	6,012	13,716		0	13,716	20,937	10,571	5,600	280	0	1,400	3,086	40,665	33.1
2000	15,724	347	0	347		0	347	15,377	3,077	12,000	0	0	300	0	15,724	18.2
2001	29,205	57	0	57		3,688	(3,631)	29,148	6,200	9,600	0	9,243	1,450	2,655	29,205	30.9
2002	85,280	28,227	0	28,227		28,201	26	57,053	6,193	7,750	0	39,910	3,200	0	85,280	61.0
2003	81,625	22,900	0	22,900		23,793	(893)	58,725	3,594	9,300	0	41,439	4,392	0	81,625	53.8
2004	68,004	19,431	0	19,431		19,117	314	48,573	5,315	9,700	0	32,752	806	0	68,004	51.7
																(1.9)
TOTALS 1982-2004	2,104,699	1,361,439	79,519	1,281,920		74,799	1,207,121	743,260	173,113	69,850	48,140	123,344	11,548	317,265	2,104,699	945.2
2005	61,804	14,750	0	14,750		14,750	0	47,054	8,189	7,956	0	24,608	602	5,699	61,804	38.0
2006	62,720	14,970	0	14,970		14,970	0	47,750	7,577	10,140	0	19,736	969	9,328	62,720	48.5
2007	49,585	10,725	0	10,725	6,139	4,586	0	38,860	7,020	9,925	0	20,886	1,817	(788)	49,585	58.2
TOTALS 2005-2007	174,109	40,445	0	40,445	6,139	34,306	0	133,664	22,786	28,021	0	65,230	3,388	14,239	174,109	144.7
TOTALS 1982-2007	2,278,808	1,401,884	79,519	1,322,365	6,139	109,105	1,207,121	876,924	195,899	97,871	48,140	188,574	14,936	331,504	2,278,808	1,089.9

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BPA's 2010 Wholesale Power Rate Case

NET Historical Conservation Savings and Expenditures 1982-2007

With Expenditure Adjustments for ConMod and C&RD

Savings Adjustments for C&RD, CRC, Market Transformation, and Building Codes

($000) [1]

Year	Total Incremental Costs / Subtotal Cost Allocations	(-) C&RD[4] Cost Adjustments	(-) ConMod[3] Cost Adjustments	(-) Market Trans.[5] Cost Adjustments	Adjusted Net Annual Costs	Total Expense Costs	Capitalized Conservation Costs	Net Conser. Savings as Adjusted
1982	66,914	0	0	0	66,914	4,974	61,940	32.4
1983	206,999	0	0	0	206,999	2,907	204,092	68.6
1984	75,094	0	0	0	75,094	8,311	66,783	16.6
1985	127,747	0	0	0	127,747	24,680	103,067	17.0
1986	104,999	0	0	0	104,999	5,256	99,743	23.5
1987	75,559	0	0	0	75,559	3,928	71,631	17.2
1988	67,105	0	(1,881)	0	65,224	6,654	58,570	15.6
1989	63,712	0	(4,726)	0	58,986	12,917	46,069	20.8
1990	78,079	0	(6,063)	0	72,016	35,796	36,220	13.2
1991	89,525	0	(6,254)	0	83,271	37,557	45,714	19.0
1992	130,647	0	(4,553)	0	126,094	63,943	62,151	37.4
1993	156,149	0	(4,179)	0	151,970	55,253	96,717	59.6
1994	180,054	0	(6,462)	0	173,592	52,350	121,242	51.3
1995	135,954	0	(4,045)	0	131,909	46,657	85,252	65.9
1996	105,806	0	(4,595)	0	101,211	48,937	52,274	56.3
1997	60,976	0	(2,744)	0	58,232	25,279	32,953	54.7
1998	58,877	0	(2,358)	0	56,519	30,188	26,331	33.4
1999	40,665	0	(280)	0	40,385	20,657	19,728	30.4
2000	15,724	0	0	0	15,724	15,377	347	14.8
2001	29,205	(9,243)	0	0	19,962	19,905	57	18.7
2002	85,280	(39,910)	0	0	45,370	17,143	28,227	26.1
2003	81,625	(41,439)	0	0	40,186	17,286	22,900	25.2
2004	68,004	(32,752)	0	0	35,252	15,821	19,431	31.4
	2,104,699	(123,344)	(48,140)	0	1,933,215	571,776	1,361,439	749.1
2005	61,804	(24,608)	0	0	37,196	22,446	14,750	20.0
2006	62,720	(19,736)	0	0	42,984	28,014	14,970	30.2
2007	49,585	0	0	0	49,585	38,860	10,725	28.5
	174,109	(44,344)	0	0	129,765	89,320	40,445	78.7
	2,278,808	(167,688)	(48,140)	0	2,062,980	661,096	1,401,884	827.8

BPA's 2010 Wholesale Power Rate Case
NET Historical Conservation Savings and Expenditures 1982-2007
With Expenditure Adjustments for ConMod and C&RD
Savings Adjustments for C&RD, CRC, Market Transformation and Building Codes

Notes Concerning Expenditure Adjustments:

1. Dollar costs for FY1982-2007 are in nominal dollars associated with the year of expenditure. Costs for FY1982-2004 were obtained from Table D of the 2005 Conservation Resource Energy Data, "The Red Book." Costs for FY2005-2007 were obtained from Table D of the 2007 Red Book.
2. Support costs are non-sector specific and consist of resource planning costs through FY 1987, Research Development & Demonstration, prior year adjustments, education efforts, and environmental conservation costs.
3. As previously noted in the table of Gross Conservation Savings, The 2005 Red Book totals have excluded the savings form ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating, and since the amount of load that BPA might serve is not known with a high degree of certainty, the conservation savings from these past investments is not available to reduce loads in the 2010-2015 time period of the 7(b)(2) rate test. The expenditures for ConMod investments were left in the Red Book to meet the Red Book's objective of accounting for all the costs of acquiring conservation savings. The expenditures for past ConMod investments has been removed from the expenditure totals that are included in the 7(b)(2) resource stack.
4. The C&RD investments were costs that were not included in BPA's revenue requirement in determining "base" rate levels for years prior to 2007. They were added after the determination of base rates and were credited back to customers as credits on their power bills in return for agreeing to invest the money in conservation efforts or renewable resources. The controls surrounding the achievement of this conservation during the 2002-2006 time period was less than past practices making the savings from these expenditures less assured. The majority of the utilities participating in this program were not "load following" customers and the Administrator's load obligations to these customers was not reduced (no decrementing of contract obligations occurred). For these reasons the savings and expenditures associated with the C&RD program for 2002-2006 was "netted" out of those years conservation efforts.

   No reduction in expenditures for the CRC program for FY 2007 were made. Unlike the FY2002-2006 time period when the C&RD costs were not included in the revenue requirement, the WP-07 revenue requirement included CRC costs. The rates charged all BPA customers included CRC costs. It would be inequitable and not feasible to conduct a CRC program where only load-following customers were eligible to participate. In order to achieve the conservation savings that occur in the service territories of full-requirements customers, BPA also needs to undertake the CRC program for BPA's other customers who pay for CRC costs. In order for BPA and it's customers to meet their portion of the NWPPC's regional targets, the total expenditures for CRC are required to be incurred. The controls surrounding documentation and verification of CRC savings were also improved compared to the controls and verification procedures that pertained to the C&RD program prior to FY 2007. As outlined in Note 3 to the "BPA 1982-2007 Historical Programmatic Conservation - After Adjustments" worksheet, 53% of the saving attributable to FY 2007 CRC efforts were attributable to non-load following loads that were not decremented for the savings achieved. These non-load following savings were removed from the 7(b)(2) resource stack for FY2007.

Notes Concerning Expenditure Adjustments - Continued:

5. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1997-2007 time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by 67%, see this calculation at Note 3 to the work-sheet "BPA 1982-2007 Programmatic Conservation - After Adjustments." The amount of market transformation expenditures were not reduced. The reason for this is the fact that the amount that BPA paid NEEA was so material in amount, that it was critical in sustaining market transformation efforts in the region. In order to achieve the 33% of savings that were included in the savings total, BPA would have needed to fund the program at approximately the same level.

6. Adjustments were made to remove the savings attributable to building codes for the years after 2001. It was thought that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should be conservatively stated with a high degree of assurance that the conservation savings would be able to reduce loads. No direct expenditures by BPA for building code efforts occurred during FY2002-2007, so no expenditure adjustments are necessary.

7. The historical expenditures reflected in the annual expenditure totals contained in the Red Book contain the direct costs along with indirect and overhead costs that were necessary to acquire the conservation savings reported for the year. The expenditure totals do not contain any costs associated with the financing of conservation efforts. The rates analysis model (RAM) finances that portion of a year's conservation expenditures that were capitalized using a 15-year amortization and financing period. The interest rates used to finance conservation investments in the 7(b)(2) Case are based on the Financing Study results on the interest rates that would apply to a Joint Operating Agency formed to undertake these investments on behalf of the 7(b)(2) Customers that was prepared by BPA's financial advisor for the rate case. The first-year expensed costs associated with conservation investments are treated as deferred charges under SFAS No. 71 and are amortized and financed over a one to fifteen-year period. The interest rates used to finance the first-year expensed costs were based on Public Financial Management's financing study for the WP-10 rate case.

BPA's 2010 Wholesale Power Rate Case

Gross Projected BPA Conservation Program Expenditures - Program Case Rates - FY 2008 - FY 2015

($1,000)

	Energy Efficiency Staffing Costs	Indirect & Overhead Costs	Corporate G&A Costs	Total Staffing, Indirect, & G&A Costs	Market Transformation Costs	Expense Agreements & Grants	CRC Costs	Infrastructure Support & Evaluation Costs	Direct Acquisition Capital Costs[1]	Total Direct Program Costs	Projected Period Costs Energy Efficiency	Capitalized/ Debt Financed	Expensed	Total Projected Conservation Savings aMW
2008	7,026	1,450	9,926	18,402	9,353	4,135	26,327	4,176	7,876	51,867	70,269	7,876	62,393	58.3
2009	7,848	3,092	9,859	20,799	10,000	5,812	32,000	7,000	27,200	82,012	102,811	27,200	75,611	58.8
2010	8,046	3,554	10,946	22,546	12,000	5,000	32,000	14,000	32,300	95,300	117,846	32,300	85,546	48.2
2011	8,330	3,779	11,154	23,263	12,000	5,000	32,000	14,000	39,100	102,100	125,363	39,100	86,263	51.6
2012	8,624	4,130	11,728	24,482	12,000	6,000	32,000	15,000	47,600	112,600	137,082	47,600	89,482	55.8
2013	8,923	4,210	12,124	25,257	12,000	6,000	32,000	15,000	47,600	112,600	137,857	47,600	90,257	55.8
2014	9,232	4,297	12,483	26,012	12,000	6,000	32,000	15,000	47,600	112,600	138,612	47,600	91,012	55.8
2015	9,537	4,508	12,901	26,946	12,000	6,000	32,000	15,000	47,600	112,600	139,546	47,600	91,946	55.8
Totals	**67,566**	**29,020**	**91,121**	**187,707**	**91,353**	**43,947**	**250,327**	**99,176**	**296,876**	**781,679**	**969,386**	**296,876**	**672,510**	**440.1**

NET BPA Conservation Program - Section 7 (b)(2) - Projected Expenditures

NET EXPENDITURES - 2008-2015

($1,000)

	Energy Efficiency Staffing Costs1	Indirect & Overhead Costs	Corporate G&A Costs	Total Staffing, Indirect, & G&A Costs	Market Transformation Costs[4]	Expense Agreements & Grants	CRC Costs[3]	Infrastructure Support & Evaluation Costs	Acquisition Capital Costs[1, 2]	Total Direct Program Costs	Projected Period Costs Energy Efficiency	Capitalized/ Debt Financed	Expensed	Total Projected Conservation Savings aMW[5]
2008	7,026	1,450	9,926	18,402	9,353	4,135	26,327	4,176	7,876	51,867	70,269	7,876	62,393	34.8
2009	7,848	3,092	9,859	20,799	10,000	5,812	32,000	7,000	27,200	82,012	102,811	27,200	75,611	40.1
2010	8,046	3,554	10,946	22,546	12,000	5,000	32,000	14,000	32,300	95,300	117,846	32,300	85,546	31.2
2011	8,330	3,779	11,154	23,263	12,000	5,000	32,000	14,000	39,100	102,100	125,363	39,100	86,263	34.6
2012	8,624	4,130	11,728	24,482	12,000	6,000	32,000	15,000	47,600	112,600	137,082	47,600	89,482	38.8
2013	8,923	4,210	12,124	25,257	12,000	6,000	32,000	15,000	47,600	112,600	137,857	47,600	90,257	38.8
2014	9,232	4,297	12,483	26,012	12,000	6,000	32,000	15,000	47,600	112,600	138,612	47,600	91,012	38.8
2015	9,537	4,508	12,901	26,946	12,000	6,000	32,000	15,000	47,600	112,600	139,546	47,600	91,946	38.8
Totals	**67,566**	**29,020**	**91,121**	**187,707**	**91,353**	**43,947**	**250,327**	**99,176**	**296,876**	**781,679**	**969,386**	**296,876**	**672,510**	**295.9**
Difference in Conservation Expenditures and Savings Contained in Resource Stack											**$0**			**144.2**

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BPA's 2010 Wholesale Power Rate Case
Projected Conservation GROSS and NET EXPENDITURES - 2008-2015
Net BPA Conservation Program - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Expenditure Amounts to Arrive at Section 7 (b)(2) Amounts

1. Dollar costs are in the nominal dollars associated with the year of expenditure. The expenditure projections for the years 2009-2011 come from BPA's Conservation Program Proposals that were finalized in the Integrated Program Review process. The expenditure projections for 2012-2015 were based on the assumption that the conservation program design for 2009-2011 continued during these four years. BPA's Direct Acquisition capital expenditures established in the IPR process were reduced by a "lapse factor" amount that reflects past historical performance in obligating these expenditures during the budget year and to meet agency wide borrowing targets. The Direct Acquisition Conservation Capital Expenditure amounts established in the IPR process, the lapse factor reduction amounts, and the net amount of these capital expenditures that are contained in the Program Case Revenue Requirement Assumptions are outlined in the table below:

Conservation Direct Acquisition Capital Costs:

Year	IPR Budget Amount	Lapse Factor Reduction	Program Case Amount
2008	7,876	0	7,876
2009	32,000	4,800	27,200
2010	38,000	5,700	32,300
2011	46,000	6,900	39,100
2012	56,000	8,400	47,600
2013	56,000	8,400	47,600
2014	56,000	8,400	47,600
2015	56,000	8,400	47,600

The conservation Direct Acquisition Capital Cost amounts contained in the 7(b)(2) Rate Test resource stack are consistent with the amounts contained in the Program Case Revenue Requirement.

Projected conservation costs for FY 2008 will be revised for the Final Rate Case Proposal based on 2008 Conservation Resource Energy Data, "The Red Book," which will be published in the spring of FY 2009. The projected conservation costs for FY 2010-2015 will be revised for the final conservation spending levels that are developed in the IPR - 2 Process which will also conclude in the spring of FY 2009. These revised amounts will be used in the Final Rate Case Proposal.

2. Debt service costs are not present in the 7(b)(2) Case Expenditure Table. Annual debt service costs are included in the annual revenue requirements for each year by the Rates Analysis Model for the 7(b)(2) Case using the interest rate projections provided by BPA's Financial Advisor associated with the hypothetical Joint Operating Agency's financing of conservation resources in performing the Section 7(b)(2) rate test.

BPA's 2010 Wholesale Power Rate Case
Projected Conservation GROSS and NET EXPENDITURES - 2008-2015
Net BPA Conservation Program - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Expenditure Amounts to Arrive at Section 7 (b)(2) Amounts - continued

3. No reduction in expenditures for the CRC program were made. The rates charged all BPA customers for FYs 2008-2015 included CRC costs. It would be inequitable and not feasible to conduct a CRC program where only load-following customers were eligible to participate. In order to achieve the conservation savings that occur in the service territories of full-requirements customers, BPA also needs to undertake the CRC program for BPA's other customers who pay for CRC costs. In order for BPA and it's customers to meet their portion of the NWPPC's regional targets, the total expenditures for CRC are required to be incurred.

4. BPA's market transformation efforts are being achieved through the Northwest Energy Efficiency Alliance (NEEA) during the 2010-2015 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately one-half of NEEA's operating budgets during this time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by sixty-four percent for the years 2008-2015, see Note 3 to the table, "Net BPA Projected Conservation Program Savings - 2008-2015 - Section 7(b)(2) Amounts."

The amount of market transformation expenditures were not reduced. The reason for this is the fact that the amount that BPA is projected to pay NEEA is so material in amount, that it is critical in sustaining market transformation efforts in the region. In order to achieve the 33% of savings that were included in the savings total, BPA would have needed to fund the program at approximately the same level.

5. The Net Conservation Savings for the years 2008-2015 are outlined in the table titled, "Net BPA Projected Conservation Program Savings - 2008-2015 - Section 7(b)(2) Amounts." Program Savings - Section 7 (b)(2) Amounts."

	A	B	C	D	E	F	G	H	I	J	K	L
1	**BPA's 2010 Wholesale Power Rate Case**											
2	**BPA Projected Conservation Program Savings - 2008-2015**											
3	**Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts**											
4	**aMW[1]**											
5												**Cumulative**
6			**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**		**Totals**
7												
8	Projected Conservation Program - Gross Saving Amounts:											
9	CRC - Non-decrement[2]		11.1	9.3	9.3	9.3	9.3	9.3	9.3	9.3		76.2
10	CRC - Equivalent-decrement[2]		12.6	10.7	10.7	10.7	10.7	10.7	10.7	10.7		87.5
11												163.7
12	Conservation Acquisition -											
13	Bi-lateral Contracts[1]		8.0	18.7	16.2	19.6	23.8	23.8	23.8	23.8		157.7
14												
15	Market Trans.- Non-decrement[3]		12.4	9.4	7.7	7.7	7.7	7.7	7.7	7.7		68.0
16	Market Trans.- Equivalent-decrement[3]		14.2	10.7	4.3	4.3	4.3	4.3	4.3	4.3		50.7
17												118.7
18	Total Projected Conservation Savings -											
19	Program Case		58.3	58.8	48.2	51.6	55.8	55.8	55.8	55.8		440.1
20												
21	Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts:											
22	Less CRC Non-Decrement[2]		(11.1)	(9.3)	(9.3)	(9.3)	(9.3)	(9.3)	(9.3)	(9.3)		(76.2)
23	Less Market Trans.- Non-decrement[3]		(12.4)	(9.4)	(7.7)	(7.7)	(7.7)	(7.7)	(7.7)	(7.7)		(68.0)
24	Net Conservation Savings for											
25	Section 7(b)(2) Case Rates		34.8	40.1	31.2	34.6	38.8	38.8	38.8	38.8		295.9
27	1/ See the footnote explanations on the following page D-23.											
29	Page 1 of 3											
31												

BPA's 2010 Wholesale Power Rate Case
BPA Projected Conservation Program Savings - 2008-2015
Net BPA Projected Conservation Program Savings - 2008-2015 - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Savings Amounts to Arrive at Savings Available to Reduce Loads per the Section 7 (b)(2) Rate Test

'1. The conservation savings projections for FY 2008 are based on preliminary budget projections, the actual historical amounts for this year will be determined in the process of compiling the historical conservation savings and related expenditure amounts in the production of the FY 2008 Conservation Resource Energy Data document, "The Red Book," that will be published in the spring of FY 2009. The conservation saving projections for the years 2009-2011 come from BPA's Conservation Program Proposals that were finalized in the Integrated Program Review process and were adjusted for the "lapse factor" adjustment that was applied to Conservation Direct Acquisition Capital program amounts as explained at Note-1 to the worksheet titled, "Projected Conservation GROSS and NET EXPENDITURES - 2008-2015." The savings projections for 2012-2015 were based on the assumption that the conservationprogram design for 2009-2011 continued during the FY2012-2015 time period.

The projected conservation savings amounts for FY 2010-2015 will be revised for the final conservation spending levels that are developed in the IPR - 2 Process which will conclude in the spring of FY 2009. These revised amounts will be used in the Final Rate Case Proposal.

2. Non-load following customer contracted power amounts (customers who purchase the slice and block power products) enjoy the benefit of CRC power bill credits and the resulting savings associated with the purchase of conservation measures in their service areas with the proceeds of these credits. The Administrator's load obligations to these utilities is not reduced for these savings, (contract power amounts have not been decremented for the conservation savings) thus BPA does not receive a direct benefit from CRC expenditures associated with non-load following customers. BPA does receive a direct benefit from load following customers associated with the conservation that occurs in those utility's service territories. Because BPA does not receive a load reduction benefit from expenditures and savings associated with non-load following loads, the portion of the CRC savings attributable to non-load following utilities has been removed from the Section 7(b)(2) resource stack. The reduction in conservation savings attributable to non-load following customer areas is estimated at forty-seven percent based on BPA's forecasted load amounts presented below:

BPA's forecasted load following loads - FY2010	4,013	53%
BPA's forecasted non-load following loads - FY2010	3,520	47%
BPA's total forecasted loads - FY2010	**7,533**	**100%**

3. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1999-2008 time frame. BPA plans to continue funding NEEA's efforts through the 2015 time period at the same level of support. BPA's "Red Book" claims one-half of the regional savings attributable to NEEA's efforts commensurate with it's level of funding. The expenditures that BPA pays NEEA however, has only a partial impact on reducing the Administrator's load obligations. The amount of load reduction from these expenditures is calculated as follows:

Notes Concerning Conservation Savings Adjustments - Continued:

BPA Forecasted FY 2010 Loads:			
Load Following Customers	4,013.0	aMW	53.27%
Non-Load Following Customers	3,520.0	aMW	46.73%
Totals	**7,533.0**	**aMW**	**100.00%**
Forecasted FY 2010 Regional Loads (No DSI's)	22,222.0	aMW	100.00%
BPA's Forecasted FY 2010 Loads (No DSI's)	7,533.0	aMW	33.90%

Of the total BPA forecasted loads for FY 2010 of 7,533aMW (33.9% of total regional loads), there is no reduction in contracted power purchases for BPA's non-load following customers associated with conservation savings in their service territories. No reduction of purchased power amounts in slice and block power purchase contracts due to NEEA savings were made during this period of time, and no decrements are forecasted for the 2010-2015 time period. For every megawatt of conservation savings that is achieved by NEEA's market transformation efforts, BPA's load obligations are reduced by approximately 18 percent (34% of 53%). Because BPA only claims half of the NEEA savings it is necessary to adjust the calculation below that is based on total regional loads by doubling the final savings amount. The adjustment necessary to reflect the savings associated with the reduction in BPA's contract power obligations, requires that the total savings from Market Transformation efforts be reduced by 64%. This percentage is derived by doubling the 18% above and subtracting this total from 100% of the gross savings contained in the Red Book (100% -(2 x 18%)) = 64%.

4. In summary, the following adjustments were made to the conservation savings projected for the years 2008-2015:

CRC Savings	76.2	aMW
Market Transformation Savings	68.0	aMW
	144.2	**aMW**

The total projected conservation savings that will be achieved by BPA's Conservation Program for FYs 2008-2015 is 440.1 aMW. The total savings included in the 7(b)(2) resource stack for those years is 295.9 aMW.

BPA's 2010 Wholesale Power Rate Case

BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures

BPA 2010 Rate Case - 7(b)(2) Resource Stack

Nominal Dollars Corresponding to the Historical Year of Acquisition

($ 000)

	Conservation Savings aMW		Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Capitalized Amortization Period Years[2]
2001 Conservation	18.7		19,905.0	57.0	19,962.0	15
2002 Conservation	26.1		17,143.0	28,227.0	45,370.0	15
2003 Conservation	25.2		17,286.0	22,900.0	40,186.0	15
2004 Conservation	31.4		15,821.0	19,431.0	35,252.0	15
2005 Conservation	20.0		22,446.0	14,750.0	37,196.0	15
2006 Conservation	30.2		28,014.0	14,970.0	42,984.0	15
2007 Conservation	28.5		38,860.0	10,725.0	49,585.0	15
2008 Conservation	34.8		62,393.0	7,876.0	70,269.0	15
2009 Conservation	40.1		75,611.0	27,200.0	102,811.0	15
Subtotal[1]	**255.0**					
2010 Conservation	31.2		85,546.0	32,300.0	117,846.0	15
2011 Conservation	34.6		86,263.0	39,100.0	125,363.0	15
2012 Conservation	38.8		89,482.0	47,600.0	137,082.0	15
2013 Conservation	38.8		90,257.0	47,600.0	137,857.0	15
2014 Conservation	38.8		91,012.0	47,600.0	138,612.0	15
2015 Conservation	38.8		91,946.0	47,600.0	139,546.0	15
Cumulative Savings						
	476.0	aMW	**$831,985.0**	**$407,936.0**	**$1,239,921.0**	
Percentages			**67.10%**	**32.90%**	**100.00%**	

Notes:

Note 1 - The amount of conservation in the resource stack for FY2001-2009 (255.0 aMW) together with billing credit resources contained in the resource stack of 10.1 aMW establish the amount of the load resource balance difference between the Program Case and the 7(b)(2) Case at the start of the Rate Test Period amounting to 265.1 aMW.

Note 2 - Historical conservation investments that occurred prior to FY 2001 will have been fully amortized before the end of the rate test period in FY 2015 based on a composite useful life of 15 years in the 7(b)(2) Case. These resources are viewed as obsolete conservation investments that are not includable in the 7(b)(2) resource stack.

Note 3 - Projected conservation costs and related conservation savings amounts for FY 2008 will be revised for the Final Rate Case Proposal based on 2008 Conservation Resource Energy Data, "The Red Book," which will be published in the spring of FY 2009. The projected conservation costs and related savings amounts for FY 2010-2015 will be revised for the final conservation spending levels that are developed in the IPR - 2 process which will also conclude in the spring of FY 2009. These revised amounts will be used in the Final Rate Case Proposal.

APPENDIX E

Residential Exchange Program Average System Cost

Summary Tables

Section 7(b)(2) Rate Test Study and Documentation

WP-10 Initial Rate Proposal
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Appendix E

Table 1: Utility Contract System Cost

	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
Avista	$ 501,406,377	$ 530,466,520	$ 548,140,453	$ 567,615,707	$ 592,130,944
Franklin PUD	$ 44,988,121	$ 45,395,809	$ 47,079,772	$ 48,718,213	$ 50,471,050
Idaho Power Company	$ 633,171,366	$ 675,334,879	$ 690,546,762	$ 711,795,327	$ 733,279,504
Pacificorp	$ 1,185,284,965	$ 1,171,841,768	$ 1,183,579,295	$ 1,236,527,476	$ 1,296,314,551
Portland General Electric	$ 1,180,832,250	$ 1,243,785,942	$ 1,280,444,383	$ 1,320,343,161	$ 1,363,011,975
Puget Sound Energy	$ 1,560,886,670	$ 1,633,879,342	$ 1,678,992,404	$ 1,729,102,958	$ 1,783,823,881
NorthWest Energy	$ 343,121,799	$ 364,781,861	$ 376,760,581	$ 389,835,771	$ 403,595,258
Snohomish PUD	$ 336,377,039	$ 358,957,291	$ 369,651,684	$ 380,139,259	$ 391,255,827

Table 2: Utility Contract System Load (MWh)

	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
Avista	9,907,952	10,202,083	10,392,785	10,641,644	10,939,225
Franklin PUD	1,057,226	1,082,349	1,098,050	1,113,979	1,130,139
Idaho Power Company	16,131,971	16,550,946	16,692,234	16,882,146	17,052,982
Pacificorp	22,915,726	23,261,468	23,493,469	23,963,339	24,442,606
Portland General Electric	19,698,019	20,173,077	20,538,686	20,964,841	21,384,009
Puget Sound Energy	24,168,246	24,823,945	25,238,407	25,688,501	26,158,159
NorthWest Energy	6,287,433	6,407,964	6,490,111	6,573,472	6,658,067
Snohomish PUD	7,401,574	7,553,461	7,622,038	7,686,464	7,753,118

Table 3: Utility ASC ($/MWh)

	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
Avista	50.61	52.00	52.74	53.34	54.13
Franklin PUD	42.55	41.94	42.88	43.73	44.66
Idaho Power Company	39.25	40.80	41.37	42.16	43.00
Pacificorp	51.72	50.38	50.38	51.60	53.04
Portland General Electric	59.95	61.66	62.34	62.98	63.74
Puget Sound Energy	64.58	65.82	66.53	67.31	68.19
NorthWest Energy	54.57	56.93	58.05	59.30	60.62
Snohomish PUD	45.45	47.52	48.50	49.46	50.46

Appendix E

Table 4: Utility Residential and Small Farm Exchange Loads (MWh)

	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Avista	3,986,348	4,034,141	3,888,712	4,031,401	4,098,536	4,209,102
Franklin PUD	352,920	361,564	367,247	372,575	377,980	383,463
Idaho Power Company	6,512,256	6,675,268	6,353,700	6,403,692	6,483,111	6,558,073
Pacificorp	9,537,744	9,631,984	9,729,476	9,826,514	10,023,044	10,223,505
Portland General Electric	8,750,249	8,837,336	8,980,520	9,143,024	9,332,440	9,518,750
Puget Sound Energy	11,920,407	12,051,542	12,250,186	12,544,453	12,951,182	13,499,041
NorthWest Energy	619,909	627,784	635,816	643,967	652,239	660,632
Snohomish PUD	3,756,771	3,821,252	3,885,583	3,944,859	4,001,408	4,059,805

	A	B	C	D	E	F	G
1	Appendix E						
2	**Table 5: Escalation Factors**						
3		**DATE**	**10/1/2011**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
4			12	13	14	15	16
5	**New Resource (True/False)**	**NR**	**FALSE**	**TRUE**	**TRUE**	**TRUE**	**TRUE**
6	**New Resource Column (5-25)**	**NRCOL**	**5**	**22**	**23**	**24**	**25**
7	**New Resource Switch (1=Used, 0=Not Used)**	**NRSW**	**0**	**0**	**0**	**0**	**0**
8	**Rate Period**	**RP**	**No**	**No**	**No**	**No**	**No**
9	**No Escalation**	**CONSTANT**	0.000%	0.000%	0.000%	0.000%	0.000%
10	**Distribution Plant**	**CD**	0.000%	0.896%	2.000%	2.000%	1.950%
11	**Inflation**	**INF**	0.000%	1.030%	2.092%	2.015%	2.022%
12	**Wages**	**WAGES**	0.000%	1.440%	2.850%	3.025%	3.100%
13	**Steam Fuel - (Coal)**	**COAL**	0.000%	0.200%	0.474%	1.375%	1.550%
14	**Steam Operations**	**SOPS**	0.000%	0.995%	2.075%	2.000%	2.025%
15	**Steam Maintenance**	**SMN**	0.000%	0.970%	2.175%	2.050%	1.925%
16	**Nuclear Fuel**	**NFUEL**	0.000%	0.000%	0.000%	0.000%	0.000%
17	**Nuclear Operations**	**NOPS**	0.000%	0.970%	2.000%	2.000%	2.000%
18	**Nuclear Maintenance**	**NMN**	0.000%	0.697%	1.700%	1.950%	1.825%
19	**Hydro Operations**	**HOPS**	0.000%	0.698%	1.250%	1.150%	1.375%
20	**Hydro Maintenance**	**HMN**	0.000%	0.896%	1.975%	1.875%	1.825%
21	**Other Fuel - (Natural Gas)**	**NATGAS**	0.000%	2.685%	3.892%	2.168%	2.416%
22	**Other Operations**	**OOPS**	0.000%	0.995%	1.675%	1.650%	1.850%
23	**Other Maintenance**	**OMN**	0.000%	0.797%	1.725%	1.800%	1.825%
24	**Transmission Operations**	**TOPS**	0.000%	0.946%	1.825%	1.925%	2.000%
25	**Transmission Maintenances**	**TMN**	0.000%	0.722%	1.825%	1.850%	1.725%
26	**Distribution Operations**	**DOPS**	0.000%	0.970%	2.025%	2.100%	2.100%
27	**Distributions Maintenances**	**DMN**	0.000%	0.797%	1.900%	1.875%	1.800%
28	**Customers Accounts**	**CACNT**	0.000%	0.970%	2.050%	2.200%	2.200%
29	**Customers Service**	**CSERV**	0.000%	0.673%	1.600%	1.900%	1.900%
30	**Customers Sales**	**CSALES**	0.000%	1.020%	2.175%	2.375%	2.300%
31	**Administrative and General**	**A&G**	0.000%	1.489%	3.025%	3.100%	3.075%
32	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
33	**Purchased Power PF (FY Esc)**	**PURCHPF**	0.000%	0.000%	0.000%	6.500%	0.000%
34	**Purchased Power Slice (FY Esc)**	**PURCHSL**	0.000%	0.000%	0.000%	2.000%	2.000%
35	**Purchased Power Generic #1 (FY Esc)**	**PURCHG1**	0.000%	0.979%	1.967%	1.933%	2.000%
36	**Purchased Power Generic #2 (FY Esc)**	**PURCHG2**	0.000%	0.979%	1.967%	1.933%	2.000%
37	**Purchased Power Generic #3 (FY Esc)**	**PURCHG3**	0.000%	0.979%	1.967%	1.933%	2.000%
38	**Steam O&M**	**SOM**	0.000%	0.970%	2.075%	1.975%	1.925%
39	**Hydro O&M**	**HOM**	0.000%	0.822%	1.625%	1.425%	1.575%
40	**Other O&M**	**OOM**	0.000%	0.896%	1.700%	1.725%	1.825%
41	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
42	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
43	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
44	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
45	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
46	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
47	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
48	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%
49	**Blank**	**ADDER**	0.000%	0.000%	0.000%	0.000%	0.000%

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APPENDIX F

Residential Exchange Program Average System Cost

Forecast Contract System Cost, Contract System Load, and ASC
FY 2010 - 2015

Table A: Avista
Table B: Franklin County PUD
Table C: Idaho Power
Table D: NorthWestern Energy
Table E: PacifiCorp
Table F: Portland General Electric
Table G: Puget Sound Energy
Table H: Snohomish County PUD

Section 7(b)(2) Rate Test Study and Documentation

WP-10 Initial Rate Proposal
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TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	15,259,132	15,259,132	15,259,132	15,259,132	15,259,132
5		Intangible Plant - Miscellaneous	3,057,183	3,057,183	3,057,183	3,057,183	3,057,183
6	**Total Intangible Plant**		18,316,315	18,316,315	18,316,315	18,316,315	18,316,315
7							
8	**Production Plant:**						
9		Steam Production	378,707,227	378,707,227	378,707,227	378,707,227	378,707,227
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	363,035,892	363,035,892	363,035,892	363,035,892	363,035,892
12		Other Production	273,034,180	273,034,180	273,034,180	273,034,180	273,034,180
13	**Total Production Plant**		1,014,777,299	1,014,777,299	1,014,777,299	1,014,777,299	1,014,777,299
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	443,832,431	443,832,431	443,832,431	443,832,431	443,832,431
17	**Total Transmission Plant**		443,832,431	443,832,431	443,832,431	443,832,431	443,832,431
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	953,315,689	973,502,433	1,000,372,390	1,033,129,441
21	**Total Distribution Plant**		0	953,315,689	973,502,433	1,000,372,390	1,033,129,441
22							
23	**General Plant:**						
24		Land and Land Rights	77,826	77,826	77,826	77,826	77,826
25		Structures and Improvements	1,342,867	1,342,867	1,342,867	1,342,867	1,342,867
26		Furniture and Equipment	283,658	286,015	287,614	289,741	292,335
27		Transportation Equipment	2,842,359	2,816,556	2,799,678	2,777,945	2,752,519
28		Stores Equipment	187,753	187,753	187,753	187,753	187,753
29		Tools and Garage Equipment	2,055,852	2,055,852	2,055,852	2,055,852	2,055,852
30		Laboratory Equipment	1,915,408	1,915,408	1,915,408	1,915,408	1,915,408
31		Power Operated Equipment	6,636,541	6,576,295	6,536,887	6,486,142	6,426,776
32		Communication Equipment	20,123,666	20,123,666	20,123,666	20,123,666	20,123,666
33		Miscellaneous Equipment	2,427	2,427	2,427	2,427	2,427
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		35,468,357	35,384,666	35,329,979	35,259,627	35,177,429
38							
39	**Total Electric Plant In-Service**		1,512,394,402	1,512,310,711	1,512,256,023	1,512,185,672	1,512,103,474
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	262,012,312	279,292,113	290,811,980	302,331,847	313,851,714
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	104,626,560	115,955,321	123,507,828	131,060,335	138,612,842
47		Other Production Plant	82,467,873	102,022,350	115,058,668	128,094,986	141,131,304
48		Transmission Plant (i)	171,315,440	186,067,958	195,902,970	205,737,982	215,572,994
49		Distribution Plant	0	349,338,893	369,277,211	389,637,729	410,560,225
50		General Plant	25,983,284	28,152,725	29,569,254	30,873,617	32,074,999
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	3,664,564	4,171,223	4,508,996	4,846,769	5,184,542
53		Amortization of Intangible Plant - Account 303	2,292,600	3,092,071	3,625,053	4,158,034	4,691,015
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	22,999,019	27,657,707	30,763,498	33,869,290	36,975,081
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		675,361,652	746,411,467	793,748,246	840,972,859	888,094,490
65							
66	**Total Net Plant**		837,032,750	765,899,244	718,507,777	671,212,814	624,008,984
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		17,115,756	17,534,406	17,819,365	18,106,359	18,399,104
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	49,904,947	49,904,947	49,904,947	49,904,947	49,904,947
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	49,904,947	49,904,947	49,904,947	49,904,947	49,904,947
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	2,366,409	2,359,645	2,370,826	2,403,423	2,440,676
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	11,280,306	11,483,191	11,626,170	11,730,835	11,810,755
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	3,942,466	3,893,799	3,861,480	3,819,285	3,769,076
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	17,589,181	17,736,635	17,858,476	17,953,543	18,020,506

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	7,080,344	6,993,214	6,935,353	6,859,809	6,769,918
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	33,691,369	33,691,369	33,691,369	33,691,369	33,691,369
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	12,910,835	12,910,835	12,910,835	12,910,835	12,910,835
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	12,823,270	12,665,468	12,560,675	12,423,858	12,261,055
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	66,505,817	66,260,886	66,098,231	65,885,871	65,633,178
121							
122	**Total Assets and Other Debits**		151,115,701	151,436,873	151,681,019	151,850,719	151,957,734

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	10,204,102	10,204,102	10,204,102	10,204,102	10,204,102
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	2,157,952	2,131,396	2,113,761	2,090,737	2,063,340
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	12,362,053	12,335,498	12,317,863	12,294,839	12,267,442
144							
145	**Total Liabilities and Other Credits**		12,362,053	12,335,498	12,317,863	12,294,839	12,267,442
146							
147							
148	**Total Rate Base**		975,786,398	905,000,619	857,870,933	810,768,694	763,699,276
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.96%	10.96%	10.96%	10.96%	10.96%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		106,967,662	99,207,983	94,041,532	88,878,090	83,718,246

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	28,559,759	28,478,117	28,613,068	29,006,474	29,456,063
164		Steam Power - Operations (Excluding 501 - Fuel)	5,587,580	5,748,634	5,867,918	5,985,276	6,106,478
165		Steam Power - Maintenance	9,228,409	9,474,951	9,681,030	9,879,488	10,069,667
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	17,055,676	17,455,560	17,673,748	17,876,990	18,122,784
172		Hydraulic - Maintenance	4,644,324	4,755,058	4,848,970	4,939,887	5,030,040
173		**Other Power Generation**					
174		Other Power - Fuel	193,926,111	207,219,574	215,284,712	219,952,264	225,266,506
175		Other Power - Operations (Excluding 547 - Fuel)	3,375,428	3,513,395	3,572,244	3,631,185	3,698,361
176		Other Power - Maintenance	3,085,204	3,153,731	3,208,133	3,265,879	3,325,481
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	239,483,073	274,620,376	293,253,017	317,490,489	346,200,640
179		System Control and Load Dispatching	480,570	480,570	480,570	480,570	480,570
180		Other Expenses	26,956,543	26,956,543	26,956,543	26,956,543	26,956,543
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	oduction Expense		532,382,677	581,856,510	609,439,953	639,465,045	674,713,133
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	19,385,753	19,981,170	20,399,274	20,810,319	21,231,208
187		Total Operations less Wheeling	6,162,386	6,379,454	6,495,878	6,620,923	6,753,342
188		Total Maintenance	3,081,782	3,136,012	3,193,244	3,252,318	3,308,420
189	**Total Transmission Expense**		28,629,921	29,496,636	30,088,396	30,683,560	31,292,970
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	9,080,121	9,281,685	9,430,179	9,609,352	9,791,930
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		9,080,121	9,281,685	9,430,179	9,609,352	9,791,930
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	11,566,887	12,050,166	12,380,445	12,718,154	13,052,712
207		Office Supplies & Expenses	2,167,837	2,258,411	2,320,312	2,383,604	2,446,306
208		(Less) Administration Expenses Transferred - Credit	20,863	21,735	22,331	22,940	23,543
209		Outside Services Employed	6,972,994	7,264,335	7,463,441	7,667,026	7,868,711
210		Property Insurance	760,522	785,797	802,869	818,742	832,859
211		Injuries and Damages	1,962,682	2,044,685	2,100,727	2,158,030	2,214,798
212		Employee Pensions & Benefits	591,616	616,335	633,228	650,501	667,612
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	4,800,597	4,960,486	5,068,494	5,169,021	5,258,552
222	**Total Administration and General Expenses**		28,802,271	29,958,480	30,747,186	31,542,138	32,318,008
223							
224	**Total Operations and Maintenance**		598,894,990	650,593,312	679,705,714	711,300,095	748,116,040

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	337,773	337,773	337,773	337,773	337,773
230		Amortization of Intangible Plant - Account 303	1,311,910	1,311,910	1,311,910	1,311,910	1,311,910
231		Steam Production Plant	11,519,867	11,519,867	11,519,867	11,519,867	11,519,867
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	7,552,507	7,552,507	7,552,507	7,552,507	7,552,507
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	13,036,318	13,036,318	13,036,318	13,036,318	13,036,318
236		Transmission Plant (i)	9,835,012	9,835,012	9,835,012	9,835,012	9,835,012
237		Distribution Plant	0	19,938,318	20,360,518	20,922,495	21,607,600
238		General Plant	1,724,761	1,710,164	1,707,735	1,704,612	1,700,969
239		Common Plant - Electric	3,105,791	3,105,791	3,105,791	3,105,791	3,105,791
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		48,423,939	48,409,343	48,406,913	48,403,791	48,400,147
245							
246							
247	**Total Operating Expenses**		647,318,929	699,002,654	728,112,627	759,703,886	796,516,187
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	0	0	0	0	0
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		0	0	0	0	0
259							
260	**STATE AND OTHER**						
261		Property	11,599,182	11,456,444	11,361,654	11,237,897	11,090,636
262		Unemployment	0	0	0	0	0
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		11,599,182	11,456,444	11,361,654	11,237,897	11,090,636
269							
270	**TOTAL TAXES**		11,599,182	11,456,444	11,361,654	11,237,897	11,090,636
271							
272							

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	238,789	238,789	238,789	238,789	238,789
279		(Less) Regulatory Debits	337,368	337,368	337,368	337,368	337,368
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		(98,579)	(98,579)	(98,579)	(98,579)	(98,579)
286							
287	**Sale for Resale:**						
288		Sales for Resale	240,708,192	255,448,672	261,636,105	268,481,181	275,490,173
289	**Total Sales for Resale**		240,708,192	255,448,672	261,636,105	268,481,181	275,490,173
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	309,017	309,017	309,017	309,017	309,017
295		Rent from Electric Property	906,381	887,066	874,432	858,163	839,130
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	12,183,659	12,183,659	12,183,659	12,183,659	12,183,659
298		Revenues from Transmission of Electricity of Others (i)	10,470,726	10,470,726	10,470,726	10,470,726	10,470,726
299							
300	**Total Other Revenues**		23,869,783	23,850,468	23,837,834	23,821,564	23,802,532
301							
302	**Total Other Included Items**		264,479,396	279,200,561	285,375,360	292,204,166	299,194,125
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE A - AVISTA
Appendix F

	A	B	C	D	E	F	G
1	AVISTA	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		***Schedule 4: Average System Cost***					
306							
307			**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
308							
309	**Total Operating Expenses**		647,318,929	699,002,654	728,112,627	759,703,886	796,516,187
310	*(From Schedule 3)*						
311							
312	**Federal Income Tax Adjusted Return on Rate Base**		106,967,662	99,207,983	94,041,532	88,878,090	83,718,246
313	*(From Schedule 2)*						
314							
315	**State and Other Taxes**		11,599,182	11,456,444	11,361,654	11,237,897	11,090,636
316	*(From Schedule 3a)*						
317							
318	**Total Other Included Items**		264,479,396	279,200,561	285,375,360	292,204,166	299,194,125
319	*(From Schedule 3b)*						
320							
321	**Total Cost**		**501,406,377**	**530,466,520**	**548,140,453**	**567,615,707**	**592,130,944**
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		501,406,377	530,466,520	548,140,453	567,615,707	592,130,944
328	(Less) New Large Single Load Costs (d)		0	0	0	0	0
329	**Total Contract System Cost**		**501,406,377**	**530,466,520**	**548,140,453**	**567,615,707**	**592,130,944**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		9,429,375	9,709,299	9,890,789	10,127,628	10,410,835
333	(Less) New Large Single Load		0	0	0	0	0
334	Total Retail Load (Net of NLSL) (d)		9,429,375	9,709,299	9,890,789	10,127,628	10,410,835
335	Distribution Loss (f)		478,577	492,784	501,996	514,016	528,390
336	**Total Contract System Load**		**9,907,952**	**10,202,083**	**10,392,785**	**10,641,644**	**10,939,225**
337							
338	**Average System Cost $/MWh**		**50.61**	**52.00**	**52.74**	**53.34**	**54.13**
339							

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	0	0	0	0	0
5		Intangible Plant - Miscellaneous	0	0	0	0	0
6	**Total Intangible Plant**		0	0	0	0	0
7							
8	**Production Plant:**						
9		Steam Production	0	0	0	0	0
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	0	0	0	0	0
12		Other Production	18,232,751	18,232,751	18,232,751	18,232,751	18,232,751
13	**Total Production Plant**		18,232,751	18,232,751	18,232,751	18,232,751	18,232,751
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	4,077,516	4,077,516	4,077,516	4,077,516	4,077,516
17	**Total Transmission Plant**		4,077,516	4,077,516	4,077,516	4,077,516	4,077,516
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	24,214	24,214	24,214	24,214	24,214
25		Structures and Improvements	802,526	802,526	802,526	802,526	802,526
26		Furniture and Equipment	498,516	504,370	507,967	511,689	515,538
27		Transportation Equipment	134,081	133,567	133,265	132,962	132,659
28		Stores Equipment	3,888	3,888	3,888	3,888	3,888
29		Tools and Garage Equipment	141,409	141,409	141,409	141,409	141,409
30		Laboratory Equipment	4,819	4,819	4,819	4,819	4,819
31		Power Operated Equipment	260	259	259	258	257
32		Communication Equipment	1,716,023	1,716,023	1,716,023	1,716,023	1,716,023
33		Miscellaneous Equipment	49,147	49,147	49,147	49,147	49,147
34		Other Tangible Property	231,532	231,532	231,532	231,532	231,532
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		3,606,416	3,611,755	3,615,049	3,618,468	3,622,014
38							
39	**Total Electric Plant In-Service**		25,916,683	25,922,022	25,925,316	25,928,735	25,932,281
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	0	0	0	0	0
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	0	0	0	0	0
47		Other Production Plant	9,538,897	10,898,824	11,805,442	12,712,060	13,618,678
48		Transmission Plant (i)	1,782,020	1,930,988	2,030,300	2,129,612	2,228,924
49		Distribution Plant	0	0	0	0	0
50		General Plant	1,183,042	1,422,111	1,579,462	1,734,572	1,887,413
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	0	0	0	0	0
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		12,503,959	14,251,923	15,415,204	16,576,244	17,735,014
65							
66	**Total Net Plant**		13,412,725	11,670,100	10,510,113	9,352,491	8,197,266
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		1,037,267	1,039,972	1,041,836	1,043,795	1,045,789
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	0	0	0	0	0
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	600,350	604,522	608,554	611,973	615,286
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	14,849	14,507	14,304	14,101	13,896
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	615,199	619,029	622,858	626,074	629,182

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	314,902	307,706	303,448	299,165	294,862
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	0	0	0	0	0
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	3,392,599	3,392,599	3,392,599	3,392,599	3,392,599
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	0	0	0	0	0
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	3,707,501	3,700,305	3,696,047	3,691,764	3,687,461
121							
122	**Total Assets and Other Debits**		5,359,967	5,359,307	5,360,741	5,361,632	5,362,431

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	3,106,648	3,106,648	3,106,648	3,106,648	3,106,648
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	3,106,648	3,106,648	3,106,648	3,106,648	3,106,648
144							
145	**Total Liabilities and Other Credits**		3,106,648	3,106,648	3,106,648	3,106,648	3,106,648
146							
147							
148	**Total Rate Base**		15,666,043	13,922,758	12,764,205	11,607,475	10,453,050
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		4.00%	4.00%	4.00%	4.00%	4.00%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		626,952	557,186	510,821	464,529	418,329

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	0	0	0	0	0
164		Steam Power - Operations (Excluding 501 - Fuel)	0	0	0	0	0
165		Steam Power - Maintenance	0	0	0	0	0
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	0	0	0	0	0
172		Hydraulic - Maintenance	0	0	0	0	0
173		**Other Power Generation**					
174		Other Power - Fuel	1,655,695	1,736,741	1,804,336	1,843,456	1,887,995
175		Other Power - Operations (Excluding 547 - Fuel)	38,528	40,103	40,774	41,447	42,214
176		Other Power - Maintenance	102,844	105,128	106,942	108,867	110,854
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	50,153,483	52,516,567	54,728,000	57,064,056	59,525,586
179		System Control and Load Dispatching	556,503	556,503	556,503	556,503	556,503
180		Other Expenses	7,068,363	7,068,363	7,068,363	7,068,363	7,068,363
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	oduction Expense		59,575,416	62,023,405	64,304,918	66,682,691	69,191,515
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	0	0	0	0	0
187		Total Operations less Wheeling	16,500	17,082	17,393	17,728	18,083
188		Total Maintenance	0	0	0	0	0
189	**Total Transmission Expense**		16,500	17,082	17,393	17,728	18,083
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	159,779	165,211	169,029	173,045	177,099
207		Office Supplies & Expenses	31,776	32,857	33,616	34,415	35,221
208		(Less) Administration Expenses Transferred - Credit	0	0	0	0	0
209		Outside Services Employed	20,658	21,360	21,854	22,373	22,897
210		Property Insurance	27,126	27,729	28,172	28,635	29,091
211		Injuries and Damages	732	757	775	793	812
212		Employee Pensions & Benefits	275,328	284,688	291,266	298,187	305,173
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	0	0	0	0	0
222	**Total Administration and General Expenses**		515,400	532,601	544,711	557,448	570,292
223							
224	**Total Operations and Maintenance**		60,107,316	62,573,087	64,867,022	67,257,867	69,779,890

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	0	0	0	0	0
230		Amortization of Intangible Plant - Account 303	0	0	0	0	0
231		Steam Production Plant	0	0	0	0	0
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	0	0	0	0	0
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	906,618	906,618	906,618	906,618	906,618
236		Transmission Plant (i)	99,312	99,312	99,312	99,312	99,312
237		Distribution Plant	0	0	0	0	0
238		General Plant	180,019	178,259	178,512	178,771	179,038
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		1,185,949	1,184,189	1,184,442	1,184,701	1,184,968
245							
246							
247	**Total Operating Expenses**		61,293,266	63,757,276	66,051,464	68,442,569	70,964,858
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	47,600	49,107	50,157	51,311	52,526
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		47,600	49,107	50,157	51,311	52,526
259							
260	**STATE AND OTHER**						
261		Property	0	0	0	0	0
262		Unemployment	6,176	6,372	6,508	6,658	6,815
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		6,176	6,372	6,508	6,658	6,815
269							
270	**TOTAL TAXES**		53,776	55,479	56,665	57,969	59,341
271							
272							

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		0	0	0	0	0
286							
287	**Sale for Resale:**						
288		Sales for Resale	16,981,691	18,970,060	19,535,171	20,242,911	20,967,600
289	**Total Sales for Resale**		16,981,691	18,970,060	19,535,171	20,242,911	20,967,600
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	4,094	3,984	3,920	3,855	3,790
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	0	0	0	0	0
298		Revenues from Transmission of Electricity of Others (i)	88	88	88	88	88
299							
300	**Total Other Revenues**		4,182	4,072	4,008	3,943	3,878
301							
302	**Total Other Included Items**		16,985,873	18,974,132	19,539,178	20,246,854	20,971,478
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE B - FRANKLIN
Appendix F

	A	B	C	D	E	F	G
1	FRANKLIN	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		***Schedule 4: Average System Cost***					
306							
307			**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
308							
309	**Total Operating Expenses**		61,293,266	63,757,276	66,051,464	68,442,569	70,964,858
310	*(From Schedule 3)*						
311							
312	**Federal Income Tax Adjusted Return on Rate Base**		626,952	557,186	510,821	464,529	418,329
313	*(From Schedule 2)*						
314							
315	**State and Other Taxes**		53,776	55,479	56,665	57,969	59,341
316	*(From Schedule 3a)*						
317							
318	**Total Other Included Items**		16,985,873	18,974,132	19,539,178	20,246,854	20,971,478
319	*(From Schedule 3b)*						
320							
321	**Total Cost**		**44,988,121**	**45,395,809**	**47,079,772**	**48,718,213**	**50,471,050**
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		44,988,121	45,395,809	47,079,772	48,718,213	50,471,050
328	(Less) New Large Single Load Costs (d)		0	0	0	0	0
329	**Total Contract System Cost**		**44,988,121**	**45,395,809**	**47,079,772**	**48,718,213**	**50,471,050**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		1,010,000	1,034,000	1,049,000	1,064,218	1,079,656
333	(Less) New Large Single Load		0	0	0	0	0
334	Total Retail Load (Net of NLSL) (d)		1,010,000	1,034,000	1,049,000	1,064,218	1,079,656
335	Distribution Loss (f)		47,226	48,349	49,050	49,762	50,483
336	**Total Contract System Load**		**1,057,226**	**1,082,349**	**1,098,050**	**1,113,979**	**1,130,139**
337							
338	**Average System Cost $/MWh**		**42.55**	**41.94**	**42.88**	**43.73**	**44.66**
339							

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	21,771,624	21,771,624	21,771,624	21,771,624	21,771,624
5		Intangible Plant - Miscellaneous	32,551,511	32,551,511	32,551,511	32,551,511	32,551,511
6	**Total Intangible Plant**		54,323,135	54,323,135	54,323,135	54,323,135	54,323,135
7							
8	**Production Plant:**						
9		Steam Production	865,431,711	865,431,711	865,431,711	865,431,711	865,431,711
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	667,750,066	667,750,066	667,750,066	667,750,066	667,750,066
12		Other Production	170,760,125	170,760,125	170,760,125	170,760,125	170,760,125
13	**Total Production Plant**		1,703,941,902	1,703,941,902	1,703,941,902	1,703,941,902	1,703,941,902
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	684,399,525	684,399,525	684,399,525	684,399,525	684,399,525
17	**Total Transmission Plant**		684,399,525	684,399,525	684,399,525	684,399,525	684,399,525
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	1,292,454,771	1,304,479,759	1,320,966,324	1,336,086,036
21	**Total Distribution Plant**		0	1,292,454,771	1,304,479,759	1,320,966,324	1,336,086,036
22							
23	**General Plant:**						
24		Land and Land Rights	6,055,675	6,055,675	6,055,675	6,055,675	6,055,675
25		Structures and Improvements	46,948,487	46,948,487	46,948,487	46,948,487	46,948,487
26		Furniture and Equipment	20,284,267	20,406,450	20,442,230	20,491,286	20,536,274
27		Transportation Equipment	21,054,112	20,849,372	20,791,017	20,712,147	20,640,948
28		Stores Equipment	733,440	733,440	733,440	733,440	733,440
29		Tools and Garage Equipment	3,009,862	3,009,862	3,009,862	3,009,862	3,009,862
30		Laboratory Equipment	6,983,353	6,983,353	6,983,353	6,983,353	6,983,353
31		Power Operated Equipment	3,202,775	3,171,630	3,162,752	3,150,755	3,139,924
32		Communication Equipment	17,671,376	17,671,376	17,671,376	17,671,376	17,671,376
33		Miscellaneous Equipment	2,065,204	2,065,204	2,065,204	2,065,204	2,065,204
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		128,008,550	127,894,848	127,863,396	127,821,584	127,784,542
38							
39	**Total Electric Plant In-Service**		2,570,673,111	2,570,559,410	2,570,527,957	2,570,486,145	2,570,449,104
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	499,464,271	535,482,691	559,494,971	583,507,251	607,519,531
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	287,003,913	306,217,492	319,026,545	331,835,598	344,644,651
47		Other Production Plant	25,522,252	32,809,498	37,667,662	42,525,826	47,383,990
48		Transmission Plant (i)	258,765,350	279,349,523	293,072,305	306,795,087	320,517,869
49		Distribution Plant	0	554,272,081	586,401,858	618,830,570	651,669,130
50		General Plant	65,995,247	75,459,432	82,041,468	88,486,557	94,939,701
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	0	0	0	0	0
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	26,764,500	26,764,500	26,764,500	26,764,500	26,764,500
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		1,163,515,532	1,256,083,135	1,318,067,450	1,379,914,818	1,441,770,241
65							
66	**Total Net Plant**		1,407,157,579	1,314,476,275	1,252,460,507	1,190,571,328	1,128,678,863
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		8,098,312	8,796,706	9,302,148	9,812,538	10,337,388
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	55,937,107	55,937,107	55,937,107	55,937,107	55,937,107
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	55,937,107	55,937,107	55,937,107	55,937,107	55,937,107
88							
89							
90		Fuel Stock	18,456,956	18,404,194	18,491,407	18,745,649	19,036,199
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	28,799,776	29,353,031	29,869,657	30,336,096	30,824,000
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	1,321,934	1,347,329	1,371,042	1,392,452	1,414,847
98		Prepayments	5,984,315	5,917,553	5,898,283	5,872,068	5,848,229
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	54,562,980	55,022,107	55,630,390	56,346,264	57,123,275

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	8,723,279	8,627,306	8,599,605	8,561,916	8,527,645
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	299,898,409	299,898,409	299,898,409	299,898,409	299,898,409
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	62,578,950	62,578,950	62,578,950	62,578,950	62,578,950
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	8,826,420	8,729,312	8,701,283	8,663,149	8,628,473
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	380,027,058	379,833,977	379,778,247	379,702,424	379,633,477
121							
122	**Total Assets and Other Debits**		498,625,457	499,589,897	500,647,892	501,798,334	503,031,247

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	19,319,547	19,319,547	19,319,547	19,319,547	19,319,547
136		Other Regulatory Liabilities	134,950,648	134,950,648	134,950,648	134,950,648	134,950,648
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	154,270,196	154,270,196	154,270,196	154,270,196	154,270,196
144							
145	**Total Liabilities and Other Credits**		154,270,196	154,270,196	154,270,196	154,270,196	154,270,196
146							
147							
148	**Total Rate Base**		1,751,512,841	1,659,795,976	1,598,838,203	1,538,099,466	1,477,439,914
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.95%	10.95%	10.95%	10.95%	10.95%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		191,765,596	181,723,912	175,049,908	168,399,885	161,758,532

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	122,746,777	122,395,891	122,975,894	124,666,711	126,598,999
164		Steam Power - Operations (Excluding 501 - Fuel)	21,019,596	21,625,459	22,074,185	22,515,669	22,971,609
165		Steam Power - Maintenance	32,042,281	32,898,309	33,613,844	34,302,916	34,963,244
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	27,077,007	27,711,850	28,058,238	28,380,897	28,771,111
172		Hydraulic - Maintenance	9,280,161	9,501,425	9,689,077	9,870,746	10,050,887
173		**Other Power Generation**					
174		Other Power - Fuel	28,339,372	29,726,575	30,883,555	31,553,136	32,315,488
175		Other Power - Operations (Excluding 547 - Fuel)	1,337,075	1,391,726	1,415,038	1,438,385	1,464,995
176		Other Power - Maintenance	981,453	1,003,252	1,020,558	1,038,928	1,057,889
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	344,015,861	405,052,045	425,669,018	452,770,287	479,809,575
179		System Control and Load Dispatching	77,489	77,489	77,489	77,489	77,489
180		Other Expenses	(118,678,522)	(118,678,522)	(118,678,522)	(118,678,522)	(118,678,522)
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	oduction Expense		468,238,549	532,705,498	556,798,374	587,936,642	619,402,762
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	11,107,188	11,448,280	11,687,834	11,923,343	12,164,493
187		Total Operations less Wheeling	11,029,613	11,418,127	11,626,507	11,850,316	12,087,323
188		Total Maintenance	6,644,271	6,761,190	6,884,581	7,011,943	7,132,899
189	**Total Transmission Expense**		28,781,073	29,627,597	30,198,922	30,785,603	31,384,714
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	10,075,956	10,299,626	10,464,405	10,663,228	10,865,830
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		10,075,956	10,299,626	10,464,405	10,663,228	10,865,830
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	28,008,904	29,147,969	29,984,389	30,850,358	31,739,443
207		Office Supplies & Expenses	10,009,160	10,416,213	10,715,112	11,024,572	11,342,292
208		(Less) Administration Expenses Transferred - Credit	15,589,075	16,223,052	16,688,582	17,170,560	17,665,403
209		Outside Services Employed	6,319,738	6,576,749	6,765,473	6,960,864	7,161,472
210		Property Insurance	2,360,411	2,442,077	2,507,871	2,574,284	2,642,822
211		Injuries and Damages	3,065,298	3,189,958	3,281,495	3,376,267	3,473,569
212		Employee Pensions & Benefits	15,681,108	16,318,827	16,787,106	17,271,929	17,769,694
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	380,401	397,940	409,978	422,687	435,685
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	2,556,981	2,648,752	2,721,107	2,794,565	2,870,284
222	**Total Administration and General Expenses**		52,792,926	54,915,433	56,483,950	58,104,967	59,769,858
223							
224	**Total Operations and Maintenance**		559,888,503	627,548,154	653,945,650	687,490,440	721,423,164

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	781,058	781,058	781,058	781,058	781,058
230		Amortization of Intangible Plant - Account 303	4,859,199	4,859,199	4,859,199	4,859,199	4,859,199
231		Steam Production Plant	24,012,280	24,012,280	24,012,280	24,012,280	24,012,280
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	12,809,053	12,809,053	12,809,053	12,809,053	12,809,053
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	4,858,164	4,858,164	4,858,164	4,858,164	4,858,164
236		Transmission Plant (i)	13,722,782	13,722,782	13,722,782	13,722,782	13,722,782
237		Distribution Plant	0	32,129,777	32,428,712	32,838,560	33,214,428
238		General Plant	6,914,184	6,870,309	6,869,210	6,867,766	6,866,505
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		67,956,720	67,912,846	67,911,746	67,910,302	67,909,042
245							
246							
247	**Total Operating Expenses**		627,845,223	695,461,000	721,857,396	755,400,742	789,332,205
248	*(Total O&M - Total Depreciation & Amortization)*						

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	70,191	72,881	74,845	76,950	79,187
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		70,191	72,881	74,845	76,950	79,187
259							
260	**STATE AND OTHER**						
261		Property	9,070,622	8,970,828	8,942,023	8,902,834	8,867,198
262		Unemployment	137,996	143,285	147,146	151,286	155,683
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		9,208,618	9,114,113	9,089,169	9,054,120	9,022,882
269							
270	**TOTAL TAXES**		9,278,808	9,186,994	9,164,014	9,131,070	9,102,069
271							
272							

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	14,110	14,110	14,110	14,110	14,110
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	2,754,122	2,754,122	2,754,122	2,754,122	2,754,122
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	5,481,083	5,481,083	5,481,083	5,481,083	5,481,083
285	**Total Other Included Items**		8,221,095	8,221,095	8,221,095	8,221,095	8,221,095
286							
287	**Sale for Resale:**						
288		Sales for Resale	141,300,682	156,963,434	161,546,016	167,225,912	173,041,822
289	**Total Sales for Resale**		141,300,682	156,963,434	161,546,016	167,225,912	173,041,822
290							
291	**Other Revenues:**						
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	6,729,901	6,590,107	6,550,262	6,496,411	6,447,797
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	146,421	146,421	146,421	146,421	146,421
298		Revenues from Transmission of Electricity of Others (i)	16,229,091	16,229,091	16,229,091	16,229,091	16,229,091
299							
300	**Total Other Revenues**		23,105,412	22,965,618	22,925,774	22,871,923	22,823,309
301							
302	**Total Other Included Items**		172,627,189	188,150,147	192,692,885	198,318,930	204,086,225
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE C - IDAHO POWER
Appendix F

	A	B	C	D	E	F	G
1	IPC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		***Schedule 4: Average System Cost***					
306							
307			**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
308							
309	**Total Operating Expenses**		627,845,223	695,461,000	721,857,396	755,400,742	789,332,205
310	*(From Schedule 3)*						
311							
312	**Federal Income Tax Adjusted Return on Rate Base**		191,765,596	181,723,912	175,049,908	168,399,885	161,758,532
313	*(From Schedule 2)*						
314							
315	**State and Other Taxes**		9,278,808	9,186,994	9,164,014	9,131,070	9,102,069
316	*(From Schedule 3a)*						
317							
318	**Total Other Included Items**		172,627,189	188,150,147	192,692,885	198,318,930	204,086,225
319	*(From Schedule 3b)*						
320							
321	**Total Cost**		**656,262,438**	**698,221,758**	**713,378,433**	**734,612,768**	**756,106,581**
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		656,262,438	698,221,758	713,378,433	734,612,768	756,106,581
328	(Less) New Large Single Load Costs (d)		23,091,072	22,886,879	22,831,672	22,817,441	22,827,077
329	**Total Contract System Cost**		**633,171,366**	**675,334,879**	**690,546,762**	**711,795,327**	**733,279,504**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		15,451,236	15,843,167	15,975,336	16,152,990	16,312,799
333	(Less) New Large Single Load		385,400	385,400	385,400	385,400	385,400
334	Total Retail Load (Net of NLSL) (d)		15,065,836	15,457,767	15,589,936	15,767,590	15,927,399
335	Distribution Loss (f)		1,066,135	1,093,179	1,102,298	1,114,556	1,125,583
336	**Total Contract System Load**		**16,131,971**	**16,550,946**	**16,692,234**	**16,882,146**	**17,052,982**
337							
338	**Average System Cost $/MWh**		**39.25**	**40.80**	**41.37**	**42.16**	**43.00**
339							

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	469	452	447	442	437
5		Intangible Plant - Miscellaneous	1,927,038	1,927,038	1,927,038	1,927,038	1,927,038
6	**Total Intangible Plant**		1,927,507	1,927,490	1,927,486	1,927,480	1,927,475
7							
8	**Production Plant:**						
9		Steam Production	0	0	0	0	0
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	0	0	0	0	0
12		Other Production	2,646,622	2,646,622	2,646,622	2,646,622	2,646,622
13	**Total Production Plant**		2,646,622	2,646,622	2,646,622	2,646,622	2,646,622
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	298,279,309	298,279,309	298,279,309	298,279,309	298,279,309
17	**Total Transmission Plant**		298,279,309	298,279,309	298,279,309	298,279,309	298,279,309
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	1,032,336,870	1,047,210,039	1,062,604,939	1,078,532,204
21	**Total Distribution Plant**		0	1,032,336,870	1,047,210,039	1,062,604,939	1,078,532,204
22							
23	**General Plant:**						
24		Land and Land Rights	94,844	94,844	94,844	94,844	94,844
25		Structures and Improvements	1,809,581	1,809,581	1,809,581	1,809,581	1,809,581
26		Furniture and Equipment	630,990	636,517	640,499	644,619	648,883
27		Transportation Equipment	6,388,045	6,387,845	6,387,705	6,387,563	6,387,419
28		Stores Equipment	99,654	99,654	99,654	99,654	99,654
29		Tools and Garage Equipment	949,746	949,746	949,746	949,746	949,746
30		Laboratory Equipment	738,144	738,144	738,144	738,144	738,144
31		Power Operated Equipment	563,748	563,731	563,718	563,706	563,693
32		Communication Equipment	4,463,935	4,463,935	4,463,935	4,463,935	4,463,935
33		Miscellaneous Equipment	42,780	42,780	42,780	42,780	42,780
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		15,781,468	15,786,778	15,790,607	15,794,573	15,798,681
38							
39	**Total Electric Plant In-Service**		318,634,907	318,640,200	318,644,023	318,647,985	318,652,087
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	0	0	0	0	0
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	0	0	0	0	0
47		Other Production Plant	2,349,170	2,510,705	2,618,395	2,726,085	2,833,775
48		Transmission Plant (i)	148,672,549	160,910,107	169,068,478	177,226,850	185,385,222
49		Distribution Plant	0	0	0	0	0
50		General Plant	10,568,316	11,596,105	12,260,004	12,913,806	13,557,340
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	752,166	882,306	969,066	1,055,825	1,142,585
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	9,246,664	10,876,965	11,963,832	13,050,699	14,137,566
59		Amortization of Other Utility Plant (a)	8,670,842	9,361,498	9,821,935	10,282,373	10,742,810
60		Amortization of Acquisition Adjustments	3,177,472	3,319,843	3,414,757	3,509,672	3,604,586
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		183,437,179	199,457,528	210,116,467	220,765,309	231,403,883
65							
66	**Total Net Plant**		135,197,727	119,182,672	108,527,557	97,882,676	87,248,204
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		4,150,395	4,244,842	4,307,712	4,373,076	4,439,686
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	13,813,036	13,813,036	13,813,036	13,813,036	13,813,036
79		Acquisition Adjustments (Electric)	3,106,285	3,106,285	3,106,285	3,106,285	3,106,285
80		**Total**	16,919,321	16,919,321	16,919,321	16,919,321	16,919,321
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	200,067	199,495	200,440	203,196	206,346
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	1,876,394	1,904,061	1,922,457	1,939,052	1,955,428
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	0	0	0	0	0
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	2,076,461	2,103,556	2,122,898	2,142,248	2,161,774

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	1,517,206	1,493,764	1,477,325	1,460,687	1,443,864
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	11,145,017	11,145,017	11,145,017	11,145,017	11,145,017
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	18	18	17	17	17
115		Miscellaneous Deferred Debits	0	0	0	0	0
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	630,750	621,004	614,170	607,253	600,259
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	13,292,990	13,259,803	13,236,530	13,212,974	13,189,156
121							
122	**Total Assets and Other Debits**		36,439,167	36,527,522	36,586,461	36,647,619	36,709,938

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	3,107,427	3,107,427	3,107,427	3,107,427	3,107,427
136		Other Regulatory Liabilities	94,871	94,871	94,871	94,871	94,871
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	3,202,298	3,202,298	3,202,298	3,202,298	3,202,298
144							
145	**Total Liabilities and Other Credits**		3,202,298	3,202,298	3,202,298	3,202,298	3,202,298
146							
147							
148	**Total Rate Base**		168,434,596	152,507,896	141,911,719	131,327,996	120,755,843
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		11.20%	11.20%	11.20%	11.20%	11.20%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		18,857,937	17,074,784	15,888,436	14,703,482	13,519,824

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	5,584,064	5,568,101	5,594,487	5,671,407	5,759,312
164		Steam Power - Operations (Excluding 501 - Fuel)	0	0	0	0	0
165		Steam Power - Maintenance	0	0	0	0	0
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	0	0	0	0	0
172		Hydraulic - Maintenance	0	0	0	0	0
173		**Other Power Generation**					
174		Other Power - Fuel	168,218	176,452	183,319	187,294	191,819
175		Other Power - Operations (Excluding 547 - Fuel)	25,704	26,755	27,203	27,652	28,164
176		Other Power - Maintenance	71,233	72,815	74,071	75,404	76,780
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	369,176,016	399,158,967	413,924,209	430,227,831	447,254,145
179		System Control and Load Dispatching	0	0	0	0	0
180		Other Expenses	9,879,017	9,879,017	9,879,017	9,879,017	9,879,017
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	oduction Expense		384,904,251	414,882,107	429,682,307	446,068,605	463,189,237
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	5,195,113	5,354,650	5,466,696	5,576,850	5,689,641
187		Total Operations less Wheeling	7,017,183	7,264,361	7,396,934	7,539,325	7,690,111
188		Total Maintenance	3,546,038	3,608,437	3,674,291	3,742,264	3,806,818
189	**Total Transmission Expense**		15,758,334	16,227,448	16,537,921	16,858,438	17,186,570
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	4,341,069	4,510,053	4,623,962	4,743,805	4,865,186
207		Office Supplies & Expenses	961,722	999,159	1,024,394	1,050,945	1,077,835
208		(Less) Administration Expenses Transferred - Credit	775,938	806,143	826,504	847,925	869,621
209		Outside Services Employed	1,037,361	1,077,742	1,104,962	1,133,600	1,162,606
210		Property Insurance	120,184	123,783	126,124	128,569	130,997
211		Injuries and Damages	1,201,688	1,248,466	1,279,998	1,313,173	1,346,773
212		Employee Pensions & Benefits	(127,728)	(132,700)	(136,051)	(139,577)	(143,149)
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	710,513	732,343	746,600	761,505	776,333
222	**Total Administration and General Expenses**		7,468,872	7,752,704	7,943,485	8,144,094	8,346,960
223							
224	**Total Operations and Maintenance**		408,131,457	438,862,259	454,163,713	471,071,137	488,722,768

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	0	0	0	0	0
230		Amortization of Intangible Plant - Account 303	81,945	81,945	81,945	81,945	81,945
231		Steam Production Plant	0	0	0	0	0
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	0	0	0	0	0
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	107,690	107,690	107,690	107,690	107,690
236		Transmission Plant (i)	8,158,372	8,158,372	8,158,372	8,158,372	8,158,372
237		Distribution Plant	0	0	0	0	0
238		General Plant	803,565	797,659	797,990	798,330	798,679
239		Common Plant - Electric	475,064	475,064	475,064	475,064	475,064
240		Common Plant - Electric	611,803	611,803	611,803	611,803	611,803
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	479,950	479,950	479,950	479,950	479,950
243		Amortization of Plant Acquisition Adjustments (Electric)	94,914	94,914	94,914	94,914	94,914
244	**Total Depreciation and Amortization**		10,813,303	10,807,397	10,807,728	10,808,068	10,808,416
245							
246							
247	**Total Operating Expenses**		418,944,760	449,669,656	464,971,441	481,879,205	499,531,184
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	675,862	700,592	717,067	735,116	754,109
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		675,862	700,592	717,067	735,116	754,109
259							
260	**STATE AND OTHER**						
261		Property	12,488,439	12,295,489	12,160,176	12,023,222	11,884,744
262		Unemployment	4,561	4,727	4,839	4,960	5,089
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		12,493,000	12,300,216	12,165,014	12,028,182	11,889,833
269							
270	**TOTAL TAXES**		13,168,861	13,000,808	12,882,081	12,763,298	12,643,941
271							
272							

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	455,431	455,431	455,431	455,431	455,431
279		(Less) Regulatory Debits	3,996,161	3,996,161	3,996,161	3,996,161	3,996,161
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		(3,540,730)	(3,540,730)	(3,540,730)	(3,540,730)	(3,540,730)
286							
287	**Sale for Resale:**						
288		Sales for Resale	60,831,012	67,953,654	69,977,966	72,513,201	75,109,146
289	**Total Sales for Resale**		60,831,012	67,953,654	69,977,966	72,513,201	75,109,146
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	580,911	571,896	565,574	559,176	552,707
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	(452,406)	(452,406)	(452,406)	(452,406)	(452,406)
298		Revenues from Transmission of Electricity of Others (i)	50,430,973	50,430,973	50,430,973	50,430,973	50,430,973
299							
300	**Total Other Revenues**		50,559,478	50,550,463	50,544,141	50,537,743	50,531,274
301							
302	**Total Other Included Items**		107,849,760	114,963,387	116,981,378	119,510,215	122,099,691
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE D - NORTHWESTERN
Appendix F

	A	B	C	D	E	F	G
1	NW	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		***Schedule 4: Average System Cost***					
306							
307			**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
308							
309		**Total Operating Expenses**	418,944,760	449,669,656	464,971,441	481,879,205	499,531,184
310		*(From Schedule 3)*					
311							
312		**Federal Income Tax Adjusted Return on Rate Base**	18,857,937	17,074,784	15,888,436	14,703,482	13,519,824
313		*(From Schedule 2)*					
314							
315		**State and Other Taxes**	13,168,861	13,000,808	12,882,081	12,763,298	12,643,941
316		*(From Schedule 3a)*					
317							
318		**Total Other Included Items**	107,849,760	114,963,387	116,981,378	119,510,215	122,099,691
319		*(From Schedule 3b)*					
320							
321		**Total Cost**	**343,121,799**	**364,781,861**	**376,760,581**	**389,835,771**	**403,595,258**
322		*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*					
323							
324							
325							
326		**Contract System Cost**					
327		Production and Transmission	343,121,799	364,781,861	376,760,581	389,835,771	403,595,258
328		(Less) New Large Single Load Costs (d)	0	0	0	0	0
329		**Total Contract System Cost**	**343,121,799**	**364,781,861**	**376,760,581**	**389,835,771**	**403,595,258**
330							
331		**Contract System Load (MWh)**					
332		Total Retail Load	6,022,446	6,137,896	6,216,581	6,296,430	6,377,459
333		(Less) New Large Single Load	0	0	0	0	0
334		Total Retail Load (Net of NLSL) (d)	6,022,446	6,137,896	6,216,581	6,296,430	6,377,459
335		Distribution Loss (f)	264,988	270,067	273,530	277,043	280,608
336		**Total Contract System Load**	**6,287,433**	**6,407,964**	**6,490,111**	**6,573,472**	**6,658,067**
337							
338		**Average System Cost $/MWh**	**54.57**	**56.93**	**58.05**	**59.30**	**60.62**
339							

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	48,106,078	48,106,078	48,106,078	48,106,078	48,106,078
5		Intangible Plant - Miscellaneous	162,594,034	162,594,034	162,594,034	162,594,034	162,594,034
6	**Total Intangible Plant**		210,700,112	210,700,112	210,700,112	210,700,112	210,700,112
7							
8	**Production Plant:**						
9		Steam Production	2,040,634,760	2,040,634,760	2,040,634,760	2,040,634,760	2,040,634,760
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	222,423,378	222,423,378	222,423,378	222,423,378	222,423,378
12		Other Production	1,426,124,523	1,426,124,523	1,426,124,523	1,426,124,523	1,426,124,523
13	**Total Production Plant**		3,689,182,661	3,689,182,661	3,689,182,661	3,689,182,661	3,689,182,661
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013
17	**Total Transmission Plant**		1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013	1,197,843,013
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	5,056,276	5,056,276	5,056,276	5,056,276	5,056,276
25		Structures and Improvements	83,077,653	83,077,653	83,077,653	83,077,653	83,077,653
26		Furniture and Equipment	25,396,446	25,506,689	25,585,137	25,747,195	25,915,717
27		Transportation Equipment	15,934,536	15,848,755	15,788,792	15,667,669	15,545,494
28		Stores Equipment	4,383,108	4,383,108	4,383,108	4,383,108	4,383,108
29		Tools and Garage Equipment	21,274,638	21,274,638	21,274,638	21,274,638	21,274,638
30		Laboratory Equipment	15,486,363	15,486,363	15,486,363	15,486,363	15,486,363
31		Power Operated Equipment	21,513,058	21,397,246	21,316,291	21,152,763	20,987,817
32		Communication Equipment	87,913,422	87,913,422	87,913,422	87,913,422	87,913,422
33		Miscellaneous Equipment	2,086,741	2,086,741	2,086,741	2,086,741	2,086,741
34		Other Tangible Property	211,525,833	212,597,469	213,360,043	214,935,364	216,573,523
35		Asset Retirement Costs for General Plant	13,152	13,152	13,152	13,152	13,152
36							
37	**Total General Plant**		493,661,225	494,641,512	495,341,616	496,794,343	498,313,904
38							
39	**Total Electric Plant In-Service**		5,591,387,011	5,592,367,297	5,593,067,402	5,594,520,129	5,596,039,690
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	1,199,972,860	1,292,032,113	1,353,404,949	1,414,777,785	1,476,150,620
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	111,154,464	119,256,200	124,657,357	130,058,514	135,459,671
47		Other Production Plant	136,167,813	202,810,746	247,239,369	291,667,991	336,096,614
48		Transmission Plant (i)	515,761,382	552,105,585	576,335,053	600,564,522	624,793,990
49		Distribution Plant	0	0	0	0	0
50		General Plant	107,244,054	208,054,459	221,596,685	234,603,212	247,576,032
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	9,032,792	10,545,807	11,554,483	12,563,159	13,571,836
53		Amortization of Intangible Plant - Account 303	137,962,031	155,533,542	167,247,882	178,962,222	190,676,563
54		Mining Plant Depreciation	10,398,961	10,398,961	10,398,961	10,398,961	10,398,961
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	45,435	45,435	45,435	45,435	45,435
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	41,850,878	45,275,669	47,558,863	49,842,057	52,125,250
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		2,269,590,670	2,596,058,517	2,760,039,037	2,923,483,858	3,086,894,973
65							
66	**Total Net Plant**		3,321,796,341	2,996,308,780	2,833,028,364	2,671,036,270	2,509,144,717
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		41,772,797	43,005,639	43,856,442	44,703,346	45,563,765
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	13,830,234	13,760,520	13,711,338	13,610,844	13,507,892
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	13,830,234	13,760,520	13,711,338	13,610,844	13,507,892
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	43,374,549	43,250,558	43,455,512	44,052,989	44,735,794
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	48,154,644	49,383,243	50,236,387	50,873,035	51,509,356
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	0	0	0	0	0
98		Prepayments	22,780,246	22,665,418	22,584,409	22,418,881	22,249,305
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	114,309,439	115,299,219	116,276,308	117,344,905	118,494,455

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	7,519,413	7,778,420	7,752,565	7,699,723	7,645,573
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	0	0	0	0	0
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	31,914	33,014	32,904	32,680	32,450
115		Miscellaneous Deferred Debits	0	0	0	0	0
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	5,753,556	5,951,738	5,931,954	5,891,522	5,850,089
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	13,304,884	13,763,171	13,717,423	13,623,925	13,528,112
121							
122	**Total Assets and Other Debits**		183,217,354	185,828,549	187,561,511	189,283,020	191,094,224

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	0	0	0	0	0
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	0	0	0	0	0
144							
145	**Total Liabilities and Other Credits**		0	0	0	0	0
146							
147							
148	**Total Rate Base**		3,505,013,695	3,182,137,329	3,020,589,875	2,860,319,290	2,700,238,941
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.87%	10.87%	10.87%	10.87%	10.87%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		380,900,209	345,812,279	328,256,439	310,839,360	293,442,955

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	256,449,549	255,716,457	256,928,234	260,460,783	264,497,829
164		Steam Power - Operations (Excluding 501 - Fuel)	49,346,088	50,768,425	51,821,865	52,858,302	53,928,678
165		Steam Power - Maintenance	75,727,470	77,750,575	79,441,642	81,070,167	82,630,760
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	12,665,274	12,962,222	13,124,245	13,275,169	13,457,691
172		Hydraulic - Maintenance	2,633,999	2,696,800	2,750,062	2,801,625	2,852,755
173		**Other Power Generation**					
174		Other Power - Fuel	170,533,299	178,880,847	185,843,021	189,872,252	194,459,735
175		Other Power - Operations (Excluding 547 - Fuel)	18,666,861	19,429,850	19,755,298	20,081,253	20,452,749
176		Other Power - Maintenance	17,567,844	17,958,052	18,267,826	18,596,647	18,936,034
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	257,764,764	265,680,485	272,361,968	340,665,453	414,897,944
179		System Control and Load Dispatching	1,056,343	1,056,343	1,056,343	1,056,343	1,056,343
180		Other Expenses	25,120,151	25,120,151	25,120,151	25,120,151	25,120,151
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	27,304,074	27,716,026	27,992,455	28,552,304	29,123,350
183	oduction Expense		914,835,717	935,736,233	954,463,112	1,034,410,451	1,121,414,021
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	47,112,104	48,558,874	49,574,963	50,573,898	51,596,755
187		Total Operations less Wheeling	9,755,067	10,098,685	10,282,985	10,480,932	10,690,551
188		Total Maintenance	11,848,963	12,057,469	12,277,516	12,504,646	12,720,350
189	**Total Transmission Expense**		68,716,134	70,715,028	72,135,464	73,559,476	75,007,655
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	8,062,565	8,241,542	8,373,394	8,532,489	8,694,606
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		8,062,565	8,241,542	8,373,394	8,532,489	8,694,606
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	35,540,692	37,152,552	38,256,911	39,401,790	40,570,007
207		Office Supplies & Expenses	2,644,811	2,764,760	2,846,942	2,932,140	3,019,075
208		(Less) Administration Expenses Transferred - Credit	5,881,612	6,148,358	6,331,118	6,520,583	6,713,911
209		Outside Services Employed	4,632,812	4,842,921	4,986,877	5,136,115	5,288,395
210		Property Insurance	9,414,825	10,188,165	10,461,467	10,712,257	10,964,005
211		Injuries and Damages	2,528,573	2,643,250	2,721,820	2,803,274	2,886,387
212		Employee Pensions & Benefits	0	0	0	0	0
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	1,826,768	1,976,820	2,029,849	2,078,510	2,127,357
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	7,566,314	7,879,654	8,092,194	8,288,659	8,486,098
222	**Total Administration and General Expenses**		54,619,647	57,346,124	59,005,244	60,675,141	62,372,699
223							
224	**Total Operations and Maintenance**		1,046,234,063	1,072,038,927	1,093,977,215	1,177,177,557	1,267,488,980

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	1,037,367	1,037,367	1,037,367	1,037,367	1,037,367
230		Amortization of Intangible Plant - Account 303	11,714,340	11,714,340	11,714,340	11,714,340	11,714,340
231		Steam Production Plant	61,372,836	61,372,836	61,372,836	61,372,836	61,372,836
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	5,401,157	5,401,157	5,401,157	5,401,157	5,401,157
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	44,428,622	44,428,622	44,428,622	44,428,622	44,428,622
236		Transmission Plant (i)	24,229,468	24,229,468	24,229,468	24,229,468	24,229,468
237		Distribution Plant	0	0	0	0	0
238		General Plant	8,016,594	14,022,757	14,047,602	14,099,042	14,152,691
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	2,283,194	2,283,194	2,283,194	2,283,194	2,283,194
244	**Total Depreciation and Amortization**		158,483,579	164,489,742	164,514,587	164,566,027	164,619,676
245							
246							
247	**Total Operating Expenses**		1,204,717,641	1,236,528,669	1,258,491,802	1,341,743,584	1,432,108,656
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	14,293,487	14,908,135	15,325,199	15,772,339	16,243,911
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		14,293,487	14,908,135	15,325,199	15,772,339	16,243,911
259							
260	**STATE AND OTHER**						
261		Property	24,592,721	25,439,818	25,355,257	25,182,436	25,005,334
262		Unemployment	685,570	715,051	735,055	756,502	779,120
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		25,278,291	26,154,869	26,090,312	25,938,937	25,784,455
269							
270	**TOTAL TAXES**		39,571,779	41,063,004	41,415,512	41,711,276	42,028,365
271							
272							

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	6,047,872	6,047,872	6,047,872	6,047,872	6,047,872
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		6,047,872	6,047,872	6,047,872	6,047,872	6,047,872
286							
287	**Sale for Resale:**						
288		Sales for Resale	407,202,338	418,893,408	411,939,133	425,168,793	438,715,257
289	**Total Sales for Resale**		407,202,338	418,893,408	411,939,133	425,168,793	438,715,257
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	44,786	44,786	44,786	44,786	44,786
295		Rent from Electric Property	3,226,885	3,193,335	3,169,883	3,122,511	3,074,728
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	21,136	21,136	21,136	21,136	21,136
298		Revenues from Transmission of Electricity of Others (i)	23,361,647	23,361,647	23,361,647	23,361,647	23,361,647
299							
300	**Total Other Revenues**		26,654,454	26,620,904	26,597,452	26,550,080	26,502,297
301							
302	**Total Other Included Items**		439,904,664	451,562,184	444,584,458	457,766,745	471,265,426
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE E - PACIFICORP
Appendix F

	A	B	C	D	E	F	G
1	PAC	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		***Schedule 4: Average System Cost***					
306							
307			**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
308							
309		**Total Operating Expenses**	1,204,717,641	1,236,528,669	1,258,491,802	1,341,743,584	1,432,108,656
310		*(From Schedule 3)*					
311							
312		**Federal Income Tax Adjusted Return on Rate Base**	380,900,209	345,812,279	328,256,439	310,839,360	293,442,955
313		*(From Schedule 2)*					
314							
315		**State and Other Taxes**	39,571,779	41,063,004	41,415,512	41,711,276	42,028,365
316		*(From Schedule 3a)*					
317							
318		**Total Other Included Items**	439,904,664	451,562,184	444,584,458	457,766,745	471,265,426
319		*(From Schedule 3b)*					
320							
321		**Total Cost**	**1,185,284,965**	**1,171,841,768**	**1,183,579,295**	**1,236,527,476**	**1,296,314,551**
322		*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*					
323							
324							
325							
326		**Contract System Cost**					
327		Production and Transmission	1,185,284,965	1,171,841,768	1,183,579,295	1,236,527,476	1,296,314,551
328		(Less) New Large Single Load Costs (d)	0	0	0	0	0
329		**Total Contract System Cost**	**1,185,284,965**	**1,171,841,768**	**1,183,579,295**	**1,236,527,476**	**1,296,314,551**
330							
331		**Contract System Load (MWh)**					
332		Total Retail Load	22,317,614	22,654,332	22,880,278	23,337,884	23,804,641
333		(Less) New Large Single Load	0	0	0	0	0
334		Total Retail Load (Net of NLSL) (d)	22,317,614	22,654,332	22,880,278	23,337,884	23,804,641
335		Distribution Loss (f)	598,112	607,136	613,191	625,455	637,964
336		**Total Contract System Load**	**22,915,726**	**23,261,468**	**23,493,469**	**23,963,339**	**24,442,606**
337							
338		**Average System Cost $/MWh**	**51.72**	**50.38**	**50.38**	**51.60**	**53.04**
339							

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	63,106,174	63,106,174	63,106,174	63,106,174	63,106,174
5		Intangible Plant - Miscellaneous	44,076,821	44,076,821	44,076,821	44,076,821	44,076,821
6	**Total Intangible Plant**		107,182,995	107,182,995	107,182,995	107,182,995	107,182,995
7							
8	**Production Plant:**						
9		Steam Production	830,266,857	830,266,857	830,266,857	830,266,857	830,266,857
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	352,114,043	352,114,043	352,114,043	352,114,043	352,114,043
12		Other Production	1,569,444,272	1,569,444,272	1,569,444,272	1,569,444,272	1,569,444,272
13	**Total Production Plant**		2,751,825,172	2,751,825,172	2,751,825,172	2,751,825,172	2,751,825,172
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	328,736,753	328,736,753	328,736,753	328,736,753	328,736,753
17	**Total Transmission Plant**		328,736,753	328,736,753	328,736,753	328,736,753	328,736,753
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	2,975,024	3,208,797	3,208,797	3,208,797	3,208,797
25		Structures and Improvements	37,139,827	40,058,220	40,058,220	40,058,220	40,058,220
26		Furniture and Equipment	19,083,275	20,718,360	20,826,101	20,954,197	21,082,649
27		Transportation Equipment	4,891,434	5,215,180	5,168,916	5,115,991	5,065,055
28		Stores Equipment	530,806	572,516	572,516	572,516	572,516
29		Tools and Garage Equipment	6,571,167	7,087,520	7,087,520	7,087,520	7,087,520
30		Laboratory Equipment	6,596,075	7,114,385	7,114,385	7,114,385	7,114,385
31		Power Operated Equipment	5,223,470	5,569,192	5,519,788	5,463,270	5,408,877
32		Communication Equipment	35,309,053	38,083,587	38,083,587	38,083,587	38,083,587
33		Miscellaneous Equipment	129,289	139,449	139,449	139,449	139,449
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	41,385	44,637	44,637	44,637	44,637
36							
37	**Total General Plant**		118,490,805	127,811,842	127,823,915	127,842,567	127,865,691
38							
39	**Total Electric Plant In-Service**		3,306,235,724	3,315,556,762	3,315,568,835	3,315,587,487	3,315,610,611
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	597,321,045	615,895,212	628,277,990	640,660,768	653,043,546
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	142,868,859	153,068,480	159,868,227	166,667,974	173,467,721
47		Other Production Plant	289,577,529	379,113,102	438,803,484	498,493,866	558,184,248
48		Transmission Plant (i)	167,224,784	177,423,764	184,223,084	191,022,404	197,821,724
49		Distribution Plant	0	0	0	0	0
50		General Plant	66,839,972	76,667,060	83,023,001	89,196,756	95,329,195
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	6,709,418	9,393,185	11,182,363	12,971,541	14,760,719
53		Amortization of Intangible Plant - Account 303	11,305,302	13,020,895	14,164,623	15,308,352	16,452,080
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		1,281,846,908	1,424,581,696	1,519,542,771	1,614,321,659	1,709,059,231
65							
66	**Total Net Plant**		2,024,388,817	1,890,975,066	1,796,026,064	1,701,265,829	1,606,551,380
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		27,110,838	27,942,036	28,504,058	29,067,050	29,645,118
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	30,535,642	30,448,353	30,592,640	31,013,263	31,493,957
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	19,449,872	19,822,476	20,058,566	20,250,160	20,446,708
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	360,000	360,000	360,000	360,000	360,000
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	1,862,945	1,898,633	1,921,246	1,939,598	1,958,423
98		Prepayments	15,353,068	15,180,994	15,046,947	14,890,626	14,737,096
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	67,561,527	67,710,456	67,979,400	68,453,646	68,996,184

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	8,733,642	8,630,472	8,556,696	8,470,619	8,386,035
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	120,639,970	120,639,970	120,639,970	120,639,970	120,639,970
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	124,118	122,652	121,604	120,380	119,178
115		Miscellaneous Deferred Debits	5,689,848	5,689,848	5,689,848	5,689,848	5,689,848
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	16,009,066	15,819,953	15,684,719	15,526,936	15,371,891
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	151,196,645	150,902,895	150,692,836	150,447,753	150,206,923
121							
122	**Total Assets and Other Debits**		245,869,010	246,555,386	247,176,294	247,968,449	248,848,225

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	144,866	144,866	144,866	144,866	144,866
136		Other Regulatory Liabilities	40,249,672	40,249,672	40,249,672	40,249,672	40,249,672
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	108,130	106,853	105,940	104,874	103,827
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	40,502,668	40,501,391	40,500,477	40,499,411	40,498,364
144							
145	**Total Liabilities and Other Credits**		40,502,668	40,501,391	40,500,477	40,499,411	40,498,364
146							
147							
148	**Total Rate Base**		2,229,755,159	2,097,029,062	2,002,701,881	1,908,734,866	1,814,901,240
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		11.01%	11.01%	11.01%	11.01%	11.01%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		245,478,891	230,866,769	220,482,072	210,137,026	199,806,666

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	67,662,247	67,468,827	67,788,545	68,720,581	69,785,724
164		Steam Power - Operations (Excluding 501 - Fuel)	11,269,981	11,594,824	11,835,415	12,072,123	12,316,583
165		Steam Power - Maintenance	22,122,727	22,713,749	23,207,771	23,683,521	24,139,427
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	7,230,879	7,400,413	7,492,915	7,579,081	7,683,287
172		Hydraulic - Maintenance	4,576,963	4,686,090	4,778,640	4,868,239	4,957,084
173		**Other Power Generation**					
174		Other Power - Fuel	247,451,629	259,564,304	269,666,738	275,513,337	282,169,984
175		Other Power - Operations (Excluding 547 - Fuel)	16,776,856	17,449,140	17,741,412	18,034,138	18,367,763
176		Other Power - Maintenance	10,465,399	10,697,851	10,882,388	11,078,271	11,280,448
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	995,599,274	1,109,092,367	1,161,805,198	1,226,660,093	1,293,854,321
179		System Control and Load Dispatching	2,555,351	2,555,351	2,555,351	2,555,351	2,555,351
180		Other Expenses	9,565,691	9,565,691	9,565,691	9,565,691	9,565,691
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	48,522,818	49,691,168	50,590,340	51,638,419	52,669,316
183	oduction Expense		1,443,799,815	1,572,479,775	1,637,910,403	1,711,968,845	1,789,344,980
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	69,226,324	71,352,202	72,845,239	74,313,070	75,816,051
187		Total Operations less Wheeling	8,819,449	9,130,111	9,296,734	9,475,695	9,665,209
188		Total Maintenance	4,114,792	4,187,199	4,263,615	4,342,491	4,417,398
189	**Total Transmission Expense**		82,160,565	84,669,511	86,405,588	88,131,256	89,898,659
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	21,488,637	22,373,859	22,965,943	23,576,022	24,197,860
207		Office Supplies & Expenses	9,132,596	9,508,813	9,760,446	10,019,728	10,284,007
208		(Less) Administration Expenses Transferred - Credit	6,272,216	6,530,599	6,703,420	6,881,493	7,062,998
209		Outside Services Employed	2,248,278	2,340,896	2,402,843	2,466,674	2,531,734
210		Property Insurance	3,762,341	3,889,054	3,972,447	4,054,393	4,137,335
211		Injuries and Damages	2,295,922	2,390,502	2,453,762	2,518,945	2,585,385
212		Employee Pensions & Benefits	17,674,821	18,402,933	18,889,934	19,391,735	19,903,210
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	1,125,298	1,163,277	1,188,221	1,212,732	1,237,541
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	957,214	991,484	1,013,558	1,035,459	1,057,662
222	**Total Administration and General Expenses**		50,162,295	52,203,664	53,567,293	54,968,730	56,396,653
223							
224	**Total Operations and Maintenance**		1,576,122,675	1,709,352,950	1,777,883,284	1,855,068,831	1,935,640,291

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	1,789,178	1,789,178	1,789,178	1,789,178	1,789,178
230		Amortization of Intangible Plant - Account 303	1,143,728	1,143,728	1,143,728	1,143,728	1,143,728
231		Steam Production Plant	12,382,778	12,382,778	12,382,778	12,382,778	12,382,778
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	6,799,747	6,799,747	6,799,747	6,799,747	6,799,747
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	39,298,678	59,690,382	59,690,382	59,690,382	59,690,382
236		Transmission Plant (i)	6,799,320	6,799,320	6,799,320	6,799,320	6,799,320
237		Distribution Plant	0	0	0	0	0
238		General Plant	7,121,676	7,087,645	7,096,992	7,108,149	7,119,378
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	19,783	19,783	19,783	19,783	19,783
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		75,354,888	95,712,562	95,721,909	95,733,066	95,744,294
245							
246							
247	**Total Operating Expenses**		1,651,477,563	1,805,065,512	1,873,605,193	1,950,801,898	2,031,384,585
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	0	0	0	0	0
257		Other Federal Taxes	6,668,419	6,637,104	6,612,709	6,584,260	6,556,320
258	**TOTAL FEDERAL**		6,668,419	6,637,104	6,612,709	6,584,260	6,556,320
259							
260	**STATE AND OTHER**						
261		Property	0	0	0	0	0
262		Unemployment	21,882,025	22,569,678	23,014,474	23,472,138	23,958,128
263		State Income, B&O, et.	546,375	543,809	541,810	539,480	537,190
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		22,428,400	23,113,487	23,556,284	24,011,618	24,495,318
269							
270	**TOTAL TAXES**		29,096,820	29,750,591	30,168,993	30,595,878	31,051,637
271							
272							

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

	A	B	C	D	E	F	G
1	PGE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	7,364,214	7,364,214	7,364,214	7,364,214	7,364,214
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	4,177,797	4,177,797	4,177,797	4,177,797	4,177,797
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	9,764,919	9,764,919	9,764,919	9,764,919	9,764,919
285	**Total Other Included Items**		21,306,930	21,306,930	21,306,930	21,306,930	21,306,930
286							
287	**Sale for Resale:**						
288		Sales for Resale	661,996,458	738,682,742	760,600,408	787,994,399	816,044,380
289	**Total Sales for Resale**		661,996,458	738,682,742	760,600,408	787,994,399	816,044,380
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	(23,300)	(23,300)	(23,300)	(23,300)	(23,300)
295		Rent from Electric Property	715,235	699,093	686,773	672,679	659,115
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	52,387,978	52,387,978	52,387,978	52,387,978	52,387,978
298		Revenues from Transmission of Electricity of Others (i)	6,781,356	6,781,356	6,781,356	6,781,356	6,781,356
299							
300	**Total Other Revenues**		59,861,269	59,845,127	59,832,807	59,818,713	59,805,149
301							
302	**Total Other Included Items**		743,164,656	819,834,799	841,740,144	869,120,042	897,156,459
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE F - PORTLAND GENERAL ELECTRIC
Appendix F

PGE	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
	Schedule 4: Average System Cost					
		10/1/2010	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
	Total Operating Expenses	1,651,477,563	1,805,065,512	1,873,605,193	1,950,801,898	2,031,384,585
	(From Schedule 3)					
	Federal Income Tax Adjusted Return on Rate Base	245,478,891	230,866,769	220,482,072	210,137,026	199,806,666
	(From Schedule 2)					
	State and Other Taxes	29,096,820	29,750,591	30,168,993	30,595,878	31,051,637
	(From Schedule 3a)					
	Total Other Included Items	743,164,656	819,834,799	841,740,144	869,120,042	897,156,459
	(From Schedule 3b)					
	Total Cost	**1,182,888,617**	**1,245,848,073**	**1,282,516,113**	**1,322,414,760**	**1,365,086,430**
	(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)					
	Contract System Cost					
	Production and Transmission	1,182,888,617	1,245,848,073	1,282,516,113	1,322,414,760	1,365,086,430
	(Less) New Large Single Load Costs (d)	2,056,367	2,062,131	2,071,730	2,071,599	2,074,454
	Total Contract System Cost	**1,180,832,250**	**1,243,785,942**	**1,280,444,383**	**1,320,343,161**	**1,363,011,975**
	Contract System Load (MWh)					
	Total Retail Load	18,718,899	19,169,620	19,516,498	19,920,821	20,318,515
	(Less) New Large Single Load	31,637	31,637	31,637	31,637	31,637
	Total Retail Load (Net of NLSL) (d)	18,687,262	19,137,983	19,484,861	19,889,184	20,286,878
	Distribution Loss (f)	1,010,757	1,035,095	1,053,825	1,075,657	1,097,131
	Total Contract System Load	**19,698,019**	**20,173,077**	**20,538,686**	**20,964,841**	**21,384,009**
	Average System Cost $/MWh	**59.95**	**61.66**	**62.34**	**62.98**	**63.74**

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	13,401,010	13,401,010	13,401,010	13,401,010	13,401,010
5		Intangible Plant - Miscellaneous	7,873,935	7,873,935	7,873,935	7,873,935	7,873,935
6	**Total Intangible Plant**		21,274,944	21,274,944	21,274,944	21,274,944	21,274,944
7							
8	**Production Plant:**						
9		Steam Production	1,003,372,944	1,003,372,944	1,003,372,944	1,003,372,944	1,003,372,944
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	171,404,775	171,404,775	171,404,775	171,404,775	171,404,775
12		Other Production	1,299,856,511	1,299,856,511	1,299,856,511	1,299,856,511	1,299,856,511
13	**Total Production Plant**		2,474,634,230	2,474,634,230	2,474,634,230	2,474,634,230	2,474,634,230
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	334,956,608	334,956,608	334,956,608	334,956,608	334,956,608
17	**Total Transmission Plant**		334,956,608	334,956,608	334,956,608	334,956,608	334,956,608
18							
19	**Distribution Plant:**		0	0	0	0	0
20		Distribution Plant	0	0	0	0	0
21	**Total Distribution Plant**		0	0	0	0	0
22							
23	**General Plant:**						
24		Land and Land Rights	3,267,520	3,354,509	3,354,509	3,354,509	3,354,509
25		Structures and Improvements	25,255,369	25,927,729	25,927,729	25,927,729	25,927,729
26		Furniture and Equipment	8,642,756	8,960,166	9,016,366	9,078,618	9,144,843
27		Transportation Equipment	104,239	105,851	105,134	104,368	103,583
28		Stores Equipment	528,315	542,380	542,380	542,380	542,380
29		Tools and Garage Equipment	2,871,158	2,947,595	2,947,595	2,947,595	2,947,595
30		Laboratory Equipment	6,778,418	6,958,876	6,958,876	6,958,876	6,958,876
31		Power Operated Equipment	121,345	123,221	122,387	121,495	120,581
32		Communication Equipment	20,612,734	21,161,497	21,161,497	21,161,497	21,161,497
33		Miscellaneous Equipment	221,740	227,643	227,643	227,643	227,643
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	16,140	16,569	16,569	16,569	16,569
36							
37	**Total General Plant**		68,419,734	70,326,038	70,380,687	70,441,280	70,505,806
38							
39	**Total Electric Plant In-Service**		2,899,285,516	2,901,191,820	2,901,246,469	2,901,307,062	2,901,371,588
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	654,863,651	691,051,710	715,177,083	739,302,456	763,427,829
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	163,809,584	181,233,626	192,849,654	204,465,682	216,081,710
47		Other Production Plant	305,121,054	374,237,644	420,315,370	466,393,096	512,470,823
48		Transmission Plant (i)	148,758,961	160,594,244	168,484,433	176,374,622	184,264,811
49		Distribution Plant					
50		General Plant	30,764,696	33,965,098	36,077,962	38,140,670	40,165,265
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	1,300,091	1,363,295	1,405,432	1,447,568	1,489,705
53		Amortization of Intangible Plant - Account 303	7,807,624	9,569,122	10,743,454	11,917,786	13,092,118
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	38,898,276	55,697,797	66,897,478	78,097,159	89,296,840
59		Amortization of Other Utility Plant (a)	62,834,638	63,112,200	63,297,241	63,482,282	63,667,323
60		Amortization of Acquisition Adjustments	63,631,682	77,646,076	86,989,005	96,331,934	105,674,862
61							
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		1,477,790,257	1,648,470,813	1,762,237,112	1,875,953,256	1,989,631,287
65							
66	**Total Net Plant**		1,421,495,259	1,252,721,007	1,139,009,357	1,025,353,806	911,740,301
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		35,230,073	36,216,851	36,901,071	37,602,829	38,322,822
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	39,966,639	39,333,443	38,936,414	38,505,881	38,058,204
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	130,840,659	130,840,659	130,840,659	130,840,659	130,840,659
79		Acquisition Adjustments (Electric)	77,568,769	77,568,769	77,568,769	77,568,769	77,568,769
80		**Total**	248,376,068	247,742,872	247,345,842	246,915,309	246,467,632
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	9,280,144	9,253,615	9,297,466	9,425,298	9,571,387
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	24,994,982	25,354,396	25,623,653	25,850,931	26,067,139
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	971,796	985,770	996,239	1,005,075	1,013,481
98		Prepayments	6,071,876	5,975,679	5,915,361	5,849,953	5,781,940
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	41,318,798	41,569,460	41,832,718	42,131,257	42,433,947

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	7,624,466	7,504,210	7,428,955	7,347,342	7,262,470
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	41,854,135	41,854,135	41,854,135	41,854,135	41,854,135
109		Other Regulatory Assets	217,021,787	217,021,787	217,021,787	217,021,787	217,021,787
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	(73,040)	(71,888)	(71,167)	(70,385)	(69,572)
115		Miscellaneous Deferred Debits	0	0	0	0	0
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	6,662,191	6,557,112	6,491,355	6,420,042	6,345,882
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	273,089,539	272,865,356	272,725,065	272,572,920	272,414,701
121							
122	**Total Assets and Other Debits**		598,014,477	598,394,538	598,804,696	599,222,315	599,639,102

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	3,547,878	3,547,878	3,547,878	3,547,878	3,547,878
136		Other Regulatory Liabilities	1,898,741	1,898,741	1,898,741	1,898,741	1,898,741
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	112,930	111,149	110,034	108,825	107,568
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	5,559,549	5,557,768	5,556,653	5,555,444	5,554,187
144							
145	**Total Liabilities and Other Credits**		5,559,549	5,557,768	5,556,653	5,555,444	5,554,187
146							
147							
148	**Total Rate Base**		2,013,950,188	1,845,557,777	1,732,257,400	1,619,020,677	1,505,825,216
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		10.77%	10.77%	10.77%	10.77%	10.77%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		216,874,550	198,741,019	186,540,137	174,346,110	162,156,526

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	62,752,429	62,573,044	62,869,562	63,733,966	64,721,819
164		Steam Power - Operations (Excluding 501 - Fuel)	15,573,518	16,022,405	16,354,868	16,681,966	17,019,774
165		Steam Power - Maintenance	20,397,058	20,941,977	21,397,463	21,836,103	22,256,446
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	5,712,495	5,846,429	5,919,507	5,987,579	6,069,904
172		Hydraulic - Maintenance	6,033,685	6,177,544	6,299,550	6,417,666	6,534,788
173		**Other Power Generation**					
174		Other Power - Fuel	138,361,372	145,134,116	150,782,842	154,051,939	157,773,971
175		Other Power - Operations (Excluding 547 - Fuel)	22,010,878	22,910,550	23,294,299	23,678,646	24,116,693
176		Other Power - Maintenance	31,124,710	31,814,524	32,363,321	32,945,861	33,547,120
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	984,963,518	1,077,413,497	1,130,522,015	1,192,096,247	1,257,771,331
179		System Control and Load Dispatching	873,300	873,300	873,300	873,300	873,300
180		Other Expenses	10,722,472	10,722,472	10,722,472	10,722,472	10,722,472
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	0	0	0	0	0
183	oduction Expense		1,298,525,435	1,400,429,857	1,461,399,201	1,529,025,746	1,601,407,618
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	94,032,430	96,920,375	98,948,423	100,942,233	102,983,789
187		Total Operations less Wheeling	3,311,976	3,428,639	3,491,211	3,558,416	3,629,585
188		Total Maintenance	4,343,425	4,419,856	4,500,518	4,583,776	4,662,846
189	**Total Transmission Expense**		101,687,831	104,768,869	106,940,152	109,084,426	111,276,219
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	40,224,200	41,117,113	41,774,927	42,568,650	43,377,455
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		40,224,200	41,117,113	41,774,927	42,568,650	43,377,455
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	7,315,428	7,605,599	7,805,226	8,013,153	8,223,079
207		Office Supplies & Expenses	4,944,409	5,140,532	5,275,457	5,415,993	5,557,879
208		(Less) Administration Expenses Transferred - Credit	51,446	53,487	54,891	56,353	57,830
209		Outside Services Employed	3,367,562	3,501,139	3,593,034	3,688,751	3,785,388
210		Property Insurance	1,668,497	1,717,878	1,752,095	1,786,565	1,820,230
211		Injuries and Damages	1,907,708	1,983,378	2,035,437	2,089,660	2,144,404
212		Employee Pensions & Benefits	6,682,351	6,947,411	7,129,762	7,319,695	7,511,454
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	1,645,927	1,697,171	1,732,589	1,768,500	1,803,804
222	**Total Administration and General Expenses**		27,480,435	28,539,621	29,268,709	30,025,965	30,788,409
223							
224	**Total Operations and Maintenance**		1,467,917,901	1,574,855,461	1,639,382,988	1,710,704,787	1,786,849,700

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	Account Description	Rate Period	FY 2012	FY 2013	FY 2014	FY 2015
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	58,078	58,078	58,078	58,078	58,078
230		Amortization of Intangible Plant - Account 303	945,357	945,357	945,357	945,357	945,357
231		Steam Production Plant	24,125,373	24,125,373	24,125,373	24,125,373	24,125,373
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	11,616,028	11,616,028	11,616,028	11,616,028	11,616,028
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	36,669,171	46,077,726	46,077,726	46,077,726	46,077,726
236		Transmission Plant (i)	7,890,189	7,890,189	7,890,189	7,890,189	7,890,189
237		Distribution Plant	0	0	0	0	0
238		General Plant	2,467,907	2,452,446	2,455,983	2,459,867	2,463,962
239		Common Plant - Electric	1,932,193	1,932,193	1,932,193	1,932,193	1,932,193
240		Common Plant - Electric	10,059,558	10,059,558	10,059,558	10,059,558	10,059,558
241		Depreciation Expense for Asset Retirement Costs	(50,562)	(50,562)	(50,562)	(50,562)	(50,562)
242		Amortization of Limited Term Electric Plant	424,390	424,390	424,390	424,390	424,390
243		Amortization of Plant Acquisition Adjustments (Electric)	5,861,545	5,861,545	5,861,545	5,861,545	5,861,545
244	**Total Depreciation and Amortization**		101,999,227	111,392,322	111,395,858	111,399,742	111,403,837
245							
246							
247	**Total Operating Expenses**		1,569,917,128	1,686,247,782	1,750,778,846	1,822,104,529	1,898,253,538
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	2,481,659	2,574,294	2,637,374	2,705,663	2,777,218
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		2,481,659	2,574,294	2,637,374	2,705,663	2,777,218
259							
260	**STATE AND OTHER**						
261		Property	17,642,806	17,364,536	17,190,398	17,001,547	16,805,156
262		Unemployment	0	0	0	0	0
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		17,642,806	17,364,536	17,190,398	17,001,547	16,805,156
269							
270	**TOTAL TAXES**		20,124,465	19,938,830	19,827,772	19,707,210	19,582,374
271							
272							

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	10,843,497	10,843,497	10,843,497	10,843,497	10,843,497
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	1,125,593	1,125,593	1,125,593	1,125,593	1,125,593
281		(Less) Loss from Disposition of Utility Plant	272,877	272,877	272,877	272,877	272,877
282		Gain from Disposition of Allowances	422,124	422,124	422,124	422,124	422,124
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	7,377,701	7,377,701	7,377,701	7,377,701	7,377,701
285	**Total Other Included Items**		19,496,037	19,496,037	19,496,037	19,496,037	19,496,037
286							
287	**Sale for Resale:**						
288		Sales for Resale	214,212,348	239,260,021	246,383,859	255,303,404	264,436,542
289	**Total Sales for Resale**		214,212,348	239,260,021	246,383,859	255,303,404	264,436,542
290							
291	**Other Revenues:**		0	0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	1,087,152	1,058,295	1,040,519	1,021,513	1,002,042
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	2,154,048	2,154,048	2,154,048	2,154,048	2,154,048
298		Revenues from Transmission of Electricity of Others (i)	9,079,888	9,079,888	9,079,888	9,079,888	9,079,888
299							
300	**Total Other Revenues**		12,321,087	12,292,230	12,274,454	12,255,448	12,235,977
301							
302	**Total Other Included Items**		246,029,472	271,048,288	278,154,350	287,054,890	296,168,556
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE G - PUGET SOUND ENERGY
Appendix F

	A	B	C	D	E	F	G
1	PSE	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		***Schedule 4: Average System Cost***					
306							
307			**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
308							
309		**Total Operating Expenses**	1,569,917,128	1,686,247,782	1,750,778,846	1,822,104,529	1,898,253,538
310		*(From Schedule 3)*					
311							
312		**Federal Income Tax Adjusted Return on Rate Base**	216,874,550	198,741,019	186,540,137	174,346,110	162,156,526
313		*(From Schedule 2)*					
314							
315		**State and Other Taxes**	20,124,465	19,938,830	19,827,772	19,707,210	19,582,374
316		*(From Schedule 3a)*					
317							
318		**Total Other Included Items**	246,029,472	271,048,288	278,154,350	287,054,890	296,168,556
319		*(From Schedule 3b)*					
320							
321		**Total Cost**	**1,560,886,670**	**1,633,879,342**	**1,678,992,404**	**1,729,102,958**	**1,783,823,881**
322		*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*					
323							
324							
325							
326		**Contract System Cost**					
327		Production and Transmission	1,560,886,670	1,633,879,342	1,678,992,404	1,729,102,958	1,783,823,881
328		(Less) New Large Single Load Costs (d)	0	0	0	0	0
329		**Total Contract System Cost**	**1,560,886,670**	**1,633,879,342**	**1,678,992,404**	**1,729,102,958**	**1,783,823,881**
330							
331		**Contract System Load (MWh)**					
332		Total Retail Load	23,006,422	23,630,599	24,025,137	24,453,594	24,900,675
333		(Less) New Large Single Load	0	0	0	0	0
334		Total Retail Load (Net of NLSL) (d)	23,006,422	23,630,599	24,025,137	24,453,594	24,900,675
335		Distribution Loss (f)	1,161,824	1,193,345	1,213,269	1,234,907	1,257,484
336		**Total Contract System Load**	**24,168,246**	**24,823,945**	**25,238,407**	**25,688,501**	**26,158,159**
337							
338		**Average System Cost $/MWh**	**64.58**	**65.82**	**66.53**	**67.31**	**68.19**
339							

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
2	**Intangible Plant:**						
3		Intangible Plant - Organization	0	0	0	0	0
4		Intangible Plant - Franchises and Consents	1,089	1,088	1,081	1,075	1,068
5		Intangible Plant - Miscellaneous	19,692,096	19,692,096	19,692,096	19,692,096	19,692,096
6	**Total Intangible Plant**		19,693,185	19,693,185	19,693,178	19,693,171	19,693,164
7							
8	**Production Plant:**						
9		Steam Production	133,715,155	133,715,155	133,715,155	133,715,155	133,715,155
10		Nuclear Production	0	0	0	0	0
11		Hydraulic Production	237,176,577	237,176,577	237,176,577	237,176,577	237,176,577
12		Other Production	0	0	0	0	0
13	**Total Production Plant**		370,891,732	370,891,732	370,891,732	370,891,732	370,891,732
14							
15	**Transmission Plant: (i)**						
16		Transmission Plant	93,329,902	93,329,902	93,329,902	93,329,902	93,329,902
17	**Total Transmission Plant**		93,329,902	93,329,902	93,329,902	93,329,902	93,329,902
18							
19	**Distribution Plant:**			0	0	0	0
20		Distribution Plant	0	819,221,455	827,549,070	835,529,000	843,945,893
21	**Total Distribution Plant**		0	819,221,455	827,549,070	835,529,000	843,945,893
22							
23	**General Plant:**						
24		Land and Land Rights	1,089,549	1,115,269	1,115,269	1,115,269	1,115,269
25		Structures and Improvements	22,836,104	23,375,172	23,375,172	23,375,172	23,375,172
26		Furniture and Equipment	1,569,300	1,612,560	1,615,347	1,618,019	1,620,836
27		Transportation Equipment	2,403,635	2,445,698	2,439,307	2,433,290	2,427,055
28		Stores Equipment	330,510	338,312	338,312	338,312	338,312
29		Tools and Garage Equipment	689,928	706,215	706,215	706,215	706,215
30		Laboratory Equipment	849,157	869,202	869,202	869,202	869,202
31		Power Operated Equipment	97,784	99,495	99,235	98,990	98,736
32		Communication Equipment	12,294,915	12,585,149	12,585,149	12,585,149	12,585,149
33		Miscellaneous Equipment	24,467	25,044	25,044	25,044	25,044
34		Other Tangible Property	0	0	0	0	0
35		Asset Retirement Costs for General Plant	0	0	0	0	0
36							
37	**Total General Plant**		42,185,348	43,172,115	43,168,252	43,164,661	43,160,990
38							
39	**Total Electric Plant In-Service**		526,100,167	527,086,934	527,083,063	527,079,466	527,075,788
40	*(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)*						
41							

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
42	**LESS:**						
43	**Depreciation Reserve**						
44		Steam Production Plant	160,671,695	173,561,961	182,155,472	190,748,983	199,342,495
45		Nuclear Production Plant	0	0	0	0	0
46		Hydraulic Production Plant	0	1,325,914	2,209,856	3,093,798	3,977,741
47		Other Production Plant	0	0	0	0	0
48		Transmission Plant (i)	32,992,764	36,615,866	39,031,267	41,446,668	43,862,069
49		Distribution Plant	0	0	0	0	0
50		General Plant	28,352,694	30,655,189	32,267,224	33,879,776	35,472,066
51		Amortization of Intangible Plant - Account 301	0	0	0	0	0
52		Amortization of Intangible Plant - Account 302	0	0	0	0	0
53		Amortization of Intangible Plant - Account 303	16,196,362	18,386,924	19,847,298	21,307,672	22,768,046
54		Mining Plant Depreciation	0	0	0	0	0
55		Amortization of Plant Held for Future Use	0	0	0	0	0
56		Capital Lease - Common Plant	0	0	0	0	0
57		Leasehold Improvements	0	0	0	0	0
58		In-Service: Depreciation of Common Plant (a)	0	0	0	0	0
59		Amortization of Other Utility Plant (a)	0	0	0	0	0
60		Amortization of Acquisition Adjustments	0	0	0	0	0
61			0				
62	**Depreciation and Amortization Reserve (Other)**		0	0	0	0	0
63							
64	**Total Depreciation and Amortization Reserve**		238,213,516	260,545,853	275,511,117	290,476,898	305,422,416
65							
66	**Total Net Plant**		287,886,652	266,541,081	251,571,946	236,602,568	221,653,372
67	***(Total Electric Plant In-Service) - (Total Depreciation & Amortization)***						

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
68							
69	**Assets and Other Debits (Comparative Balance Sheet)**						
70							
71	**Cash Working Capital (f)**		6,779,862	6,963,621	7,094,501	7,225,111	7,358,611
72							
73	**Utility Plant**		0	0	0	0	0
74		(Utility Plant) Held For Future Use	0	0	0	0	0
75		(Utility Plant) Completed Construction - Not Classified	0	0	0	0	0
76		Nuclear Fuel	0	0	0	0	0
77		Construction Work in Progress (CWIP)	0	0	0	0	0
78		Common Plant	0	0	0	0	0
79		Acquisition Adjustments (Electric)	0	0	0	0	0
80		**Total**	0	0	0	0	0
81							
82							
83		Investment in Associated Companies	0	0	0	0	0
84		Other Investment	0	0	0	0	0
85		Long-Term Portion of Derivative Assets	0	0	0	0	0
86		Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
87		**Total**	0	0	0	0	0
88							
89							
90		Fuel Stock	0	0	0	0	0
91		Fuel Stock Expenses Undistributed	0	0	0	0	0
92		Plant Materials and Operating Supplies	4,425,412	4,495,337	4,559,815	4,623,136	4,686,291
93		Merchandise (Major Only)	0	0	0	0	0
94		Other Materials and Supplies (Major only)	0	0	0	0	0
95		EPA Allowance Inventory	0	0	0	0	0
96		EPA Allowances Withheld	0	0	0	0	0
97		Stores Expense Undistributed	(77,211)	(78,431)	(79,556)	(80,661)	(81,763)
98		Prepayments	264,163	260,343	258,664	257,076	255,422
99		Derivative Instrument Assets	0	0	0	0	0
100		Less: Long-Term Portion of Derivative Assets	0	0	0	0	0
101		Derivative Instrument Assets - Hedges	0	0	0	0	0
102		Less: Long-Term Portion of Derivative Assets - Hedges	0	0	0	0	0
103		**Total**	4,612,365	4,677,248	4,738,923	4,799,551	4,859,951

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
104							
105							
106		Unamortized Debt Expenses	2,374,997	2,341,282	2,326,808	2,313,105	2,298,827
107		Extraordinary Property Losses	0	0	0	0	0
108		Unrecovered Plant and Regulatory Study Costs	0	0	0	0	0
109		Other Regulatory Assets	0	0	0	0	0
110		Prelim. Survey and Investigation Charges (Electric)	0	0	0	0	0
111		Preliminary Natural Gas Survey and Investigation Charges	0	0	0	0	0
112		Other Preliminary Survey and Investigation Charges	0	0	0	0	0
113		Clearing Accounts	0	0	0	0	0
114		Temporary Facilities	0	0	0	0	0
115		Miscellaneous Deferred Debits	16,522,224	16,522,224	16,522,224	16,522,224	16,522,224
116		Deferred Losses from Disposition of Utility Plant	0	0	0	0	0
117		Research, Development, and Demonstration Expenditures	0	0	0	0	0
118		Unamortized Loss on Reacquired Debt	11,059,028	10,902,036	10,834,639	10,770,834	10,704,346
119		Accumulated Deferred Income Taxes	0	0	0	0	0
120		**Total**	29,956,249	29,765,542	29,683,670	29,606,163	29,525,396
121							
122	**Total Assets and Other Debits**		41,348,476	41,406,411	41,517,094	41,630,825	41,743,958

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
123							
124	**Liabilities and Other Credits (Comparative Balance Sheet)**						
125		**CURRENT AND ACCRUED LIABILITIES**					
126		Derivative Instrument Liabilities	0	0	0	0	0
127		***(less) Long-Term Portion of Derivative Instrument Liabilities***	0	0	0	0	0
128		Derivative Instrument Liabilities - Hedges	0	0	0	0	0
129		***(less) Long-Term Portion of Derivative Instrument Liabilities - Hedges***	0	0	0	0	0
130		**Total**	0	0	0	0	0
131		**DEFERRED CREDITS**					
132		Long-Term Portion of Derivative Instrument Liabilities	0	0	0	0	0
133		Long-Term Portion of Derivative Instrument Liabilities - Hedges	0	0	0	0	0
134		Customer Advances for Construction	0	0	0	0	0
135		Other Deferred Credits	6,752,685	6,752,685	6,752,685	6,752,685	6,752,685
136		Other Regulatory Liabilities	0	0	0	0	0
137		Accumulated Deferred Investment Tax Credits	0	0	0	0	0
138		Deferred Gains from Disposition of Utility Plant	0	0	0	0	0
139		Unamortized Gain on Reacquired Debt	0	0	0	0	0
140		Accumulated Deferred Income Taxes-Accel. Amort.	0	0	0	0	0
141		Accumulated Deferred Income Taxes-Property	0	0	0	0	0
142		Accumulated Deferred Income Taxes-Other	0	0	0	0	0
143		**Total**	6,752,685	6,752,685	6,752,685	6,752,685	6,752,685
144							
145	**Total Liabilities and Other Credits**		6,752,685	6,752,685	6,752,685	6,752,685	6,752,685
146							
147							
148	**Total Rate Base**		322,482,443	301,194,807	286,336,355	271,480,709	256,644,644
149	*(Total Net Plant + Debits - Credits)*						
150							
151							
152	**Federal Income Tax Adjusted Weighted Cost of Capital**		5.27%	5.27%	5.27%	5.27%	5.27%
153							
154	**Federal Income Tax Adjusted Return on Rate Base**		16,994,825	15,872,966	15,089,926	14,307,033	13,525,173

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
155							
156							
157		***Schedule 3: Expenses***					
158		**Account Description**					
159							
160							
161	**Power Production Expenses:**						
162		**Steam Power Generation**					
163		Steam Power - Fuel	1,333,519	1,329,707	1,336,008	1,354,377	1,375,370
164		Steam Power - Operations (Excluding 501 - Fuel)	0	0	0	0	0
165		Steam Power - Maintenance	0	0	0	0	0
166		**Nuclear Power Generation**					
167		Nuclear - Fuel	0	0	0	0	0
168		Nuclear - Operation (Excluding 518 - Fuel)	0	0	0	0	0
169		Nuclear - Maintenance	0	0	0	0	0
170		**Hydraulic Power Generation**					
171		Hydraulic - Operation	1,085,643	1,110,796	1,124,680	1,137,614	1,153,255
172		Hydraulic - Maintenance	1,180,931	1,209,087	1,232,967	1,256,085	1,279,008
173		**Other Power Generation**					
174		Other Power - Fuel	0	0	0	0	0
175		Other Power - Operations (Excluding 547 - Fuel)	0	0	0	0	0
176		Other Power - Maintenance	0	0	0	0	0
177		**Other Power Supply Expenses**					
178		Purchased Power (Excluding REP Reversal)	312,018,163	340,759,644	353,235,418	366,048,486	379,524,945
179		System Control and Load Dispatching	0	0	0	0	0
180		Other Expenses	6,628,227	6,628,227	6,628,227	6,628,227	6,628,227
181		BPA REP Reversal	0	0	0	0	0
182		Public Purpose Charges (h)	12,173,715	12,423,529	12,536,322	12,642,286	12,751,915
183	**Total Production Expense**		334,420,197	363,460,990	376,093,622	389,067,075	402,712,720
184							
185	**Transmission Expenses: (i)**						
186		Transmission of Electricity to Others (Wheeling)	37,567,085	38,720,775	39,531,003	40,327,552	41,143,176
187		Total Operations less Wheeling	131,455	136,085	138,569	141,236	144,061
188		Total Maintenance	0	0	0	0	0
189	**Total Transmission Expense**		37,698,540	38,856,860	39,669,571	40,468,788	41,287,237
190							
191	**Distribution Expense:**						
192		Total Operations	0	0	0	0	0
193		Total Maintenance	0	0	0	0	0
194	**Total Distribution Expense**		0	0	0	0	0

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
195							
196	**Customer and Sales Expenses:**						
197		Total Customer Accounts	0	0	0	0	0
198		Customer Service and Information	0	0	0	0	0
199		Customer assistance expenses (Major only)	0	0	0	0	0
200		Customer Service and Information	0	0	0	0	0
201		Total Sales Expense	0	0	0	0	0
202	**Total Customer and Sales Expenses**		0	0	0	0	0
203							
204	**Administration and General Expense:**						
205		**Operation**					
206		Administration and General Salaries	3,106,635	3,215,258	3,296,854	3,383,774	3,471,418
207		Office Supplies & Expenses	1,307,754	1,353,480	1,387,828	1,424,418	1,461,312
208		(Less) Administration Expenses Transferred - Credit	1,455,868	1,506,773	1,545,011	1,585,745	1,626,818
209		Outside Services Employed	1,415,943	1,465,451	1,502,641	1,542,258	1,582,204
210		Property Insurance	222,997	229,967	235,459	241,329	247,214
211		Injuries and Damages	417,205	431,793	442,751	454,424	466,194
212		Employee Pensions & Benefits	521,048	539,266	552,951	567,530	582,229
213		Franchise Requirements	0	0	0	0	0
214		Regulatory Commission Expenses	0	0	0	0	0
215		(Less) Duplicate Charges - Credit	0	0	0	0	0
216		General Advertising Expenses	0	0	0	0	0
217		Miscellaneous General Expenses	0	0	0	0	0
218		Rents	0	0	0	0	0
219		Transportation Expenses (Non Major)	0	0	0	0	0
220		**Maintenance**	0	0	0	0	0
221		Maintenance of General Plant	2,109,845	2,175,560	2,227,086	2,282,191	2,337,407
222	**Total Administration and General Expenses**		7,645,558	7,904,002	8,100,559	8,310,177	8,521,162
223							
224	**Total Operations and Maintenance**		379,764,295	410,221,852	423,863,752	437,846,040	452,521,118

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
225							
226							
227	**Depreciation and Amortization:**						
228		Amortization of Intangible Plant - Account 301	0	0	0	0	0
229		Amortization of Intangible Plant - Account 302	0	0	0	0	0
230		Amortization of Intangible Plant - Account 303	1,460,374	1,460,374	1,460,374	1,460,374	1,460,374
231		Steam Production Plant	8,593,511	8,593,511	8,593,511	8,593,511	8,593,511
232		Nuclear Production Plant	0	0	0	0	0
233		Hydraulic Production Plant - Conventional	0	883,942	883,942	883,942	883,942
234		Hydraulic Production Plant - Pumped Storage	0	0	0	0	0
235		Other Production Plant	0	0	0	0	0
236		Transmission Plant (i)	2,415,401	2,415,401	2,415,401	2,415,401	2,415,401
237		Distribution Plant	0	0	0	0	0
238		General Plant	1,837,470	1,824,308	1,824,680	1,825,036	1,825,409
239		Common Plant - Electric	0	0	0	0	0
240		Common Plant - Electric	0	0	0	0	0
241		Depreciation Expense for Asset Retirement Costs	0	0	0	0	0
242		Amortization of Limited Term Electric Plant	0	0	0	0	0
243		Amortization of Plant Acquisition Adjustments (Electric)	0	0	0	0	0
244	**Total Depreciation and Amortization**		14,306,756	15,177,536	15,177,909	15,178,265	15,178,638
245							
246							
247	**Total Operating Expenses**		394,071,052	425,399,388	439,041,661	453,024,305	467,699,756
248	*(Total O&M - Total Depreciation & Amortization)*						

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
249							
250		***Schedule 3A Items: Taxes (Including Income Taxes)***					
251		**Account Description**					
252							
253							
254	**FEDERAL**						
255		Income Tax (Included on Schedule 2)	0	0	0	0	0
256		Employment Tax	126,519	130,648	133,736	137,162	140,749
257		Other Federal Taxes	0	0	0	0	0
258	**TOTAL FEDERAL**		126,519	130,648	133,736	137,162	140,749
259							
260	**STATE AND OTHER**						
261		Property	50,937	50,214	49,903	49,609	49,303
262		Unemployment	10,321	10,658	10,910	11,189	11,482
263		State Income, B&O, et.	0	0	0	0	0
264		Franchise Fees	0	0	0	0	0
265		Regulatory Commission	0	0	0	0	0
266		City/Municipal	0	0	0	0	0
267		Other	0	0	0	0	0
268	**TOTAL STATE AND OTHER TAXES**		61,258	60,872	60,813	60,799	60,785
269							
270	**TOTAL TAXES**		187,777	191,520	194,549	197,961	201,534
271							
272							

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
273		***Schedule 3B: Other Included Items***					
274		**Account Description**					
275							
276							
277	**Other Included Items:**						
278		Regulatory Credits	0	0	0	0	0
279		(Less) Regulatory Debits	0	0	0	0	0
280		Gain from Disposition of Utility Plant	0	0	0	0	0
281		(Less) Loss from Disposition of Utility Plant	0	0	0	0	0
282		Gain from Disposition of Allowances	0	0	0	0	0
283		(Less) Loss from Disposition of Allowances	0	0	0	0	0
284		Miscellaneous Nonoperating Income	0	0	0	0	0
285	**Total Other Included Items**		0	0	0	0	0
286							
287	**Sale for Resale:**						
288		Sales for Resale	65,199,332	72,833,457	75,003,137	77,720,429	80,502,791
289	**Total Sales for Resale**		65,199,332	72,833,457	75,003,137	77,720,429	80,502,791
290							
291	**Other Revenues:**			0	0	0	0
292		Forfeited Discounts	0	0	0	0	0
293		Miscellaneous Service Revenues	0	0	0	0	0
294		Sales of Water and Water Power	0	0	0	0	0
295		Rent from Electric Property	204,305	200,149	198,339	196,635	194,869
296		Interdepartmental Rents	0	0	0	0	0
297		Other Electric Revenues	444,034	444,034	444,034	444,034	444,034
298		Revenues from Transmission of Electricity of Others (i)	9,028,943	9,028,943	9,028,943	9,028,943	9,028,943
299			0				
300	**Total Other Revenues**		9,677,282	9,673,126	9,671,316	9,669,612	9,667,846
301							
302	**Total Other Included Items**		74,876,614	82,506,583	84,674,453	87,390,041	90,170,637
303	*(Total Disposition of Plant + Total Sales for Resale + Total Other Revenue)*						

TABLE H - SNOHOMISH
Appendix F

	A	B	C	D	E	F	G
1	SNO	**Account Description**	**Rate Period**	**FY 2012**	**FY 2013**	**FY 2014**	**FY 2015**
304							
305		***Schedule 4: Average System Cost***					
306							
307			**10/1/2010**	**4/1/2012**	**4/1/2013**	**4/1/2014**	**4/1/2015**
308							
309	**Total Operating Expenses**		394,071,052	425,399,388	439,041,661	453,024,305	467,699,756
310	*(From Schedule 3)*						
311							
312	**Federal Income Tax Adjusted Return on Rate Base**		16,994,825	15,872,966	15,089,926	14,307,033	13,525,173
313	*(From Schedule 2)*						
314							
315	**State and Other Taxes**		187,777	191,520	194,549	197,961	201,534
316	*(From Schedule 3a)*						
317							
318	**Total Other Included Items**		74,876,614	82,506,583	84,674,453	87,390,041	90,170,637
319	*(From Schedule 3b)*						
320							
321	**Total Cost**		**336,377,039**	**358,957,291**	**369,651,684**	**380,139,259**	**391,255,827**
322	*(Total Operating Expenses + Return on Rate Base + State and Other Taxes - Total Other Included Items)*						
323							
324							
325							
326	**Contract System Cost**						
327	Production and Transmission		336,377,039	358,957,291	369,651,684	380,139,259	391,255,827
328	(Less) New Large Single Load Costs (d)		0	0	0	0	0
329	**Total Contract System Cost**		**336,377,039**	**358,957,291**	**369,651,684**	**380,139,259**	**391,255,827**
330							
331	**Contract System Load (MWh)**						
332	Total Retail Load		7,049,119	7,193,772	7,259,084	7,320,442	7,383,922
333	(Less) New Large Single Load		0	0	0	0	0
334	Total Retail Load (Net of NLSL) (d)		7,049,119	7,193,772	7,259,084	7,320,442	7,383,922
335	Distribution Loss (f)		352,456	359,689	362,954	366,022	369,196
336	**Total Contract System Load**		**7,401,574**	**7,553,461**	**7,622,038**	**7,686,464**	**7,753,118**
337							
338	**Average System Cost $/MWh**		**45.45**	**47.52**	**48.50**	**49.46**	**50.46**
339							

APPENDIX G

Residential Exchange Program Average System Cost

Purchase Power and
Sales for Resale

Table A: Avista
Table B: Franklin County PUD
Table C: Idaho Power
Table D: NorthWestern Energy
Table E: PacifiCorp
Table F: Portland General Electric
Table G: Puget Sound Energy
Table H: Snohomish County PUD

Section 7(b)(2) Rate Test Study and Documentation

WP-10 Initial Rate Proposal
WP-10-E-BPA-06

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TABLE A - AVISTA
Appendix G

	C	D	E	F	G	H
3	**Avista Utilities**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
5	**Inflation Factor Date-to-Date**	**1.00000**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
8	**Total Purchased Power ($)**	**$ 239,483,073**	**$ 274,620,376**	**$ 293,253,017**	**$ 317,490,489**	**$ 346,200,640**
9	**Total Sale for Resale Credit ($)**	**$ 240,708,192**	**$ 255,448,672**	**$ 261,636,105**	**$ 268,481,181**	**$ 275,490,173**
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	2,900,972	2,900,972	2,900,972	2,900,972	2,900,972
14	New Resource LT & IT Purchased Power (MWh)					
15	LT & IT Terminated Contracts (MWh)					
17	**Total LT & IT Purchased Power (MWh)**	**2,900,972**	**2,900,972**	**2,900,972**	**2,900,972**	**2,900,972**
20	Base Period LT & IT Sales for Resale (MWh)	770,428.00	770,428.00	770,428.00	770,428.00	770,428.00
21	New Resource LT & IT Sales for Resale (MWh)	1,423,334.00	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
24	**Total LT & IT Sales for Resale (MWh)**	**2,193,762**	**2,193,762**	**2,193,762**	**2,193,762**	**2,193,762**
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 91,493,181	$ 94,302,854	$ 96,276,130	$ 98,216,094	$ 100,202,514
29	New Resource LT Purchases, Market ($)	$ 22,489,466	$ 23,180,571	$ 23,665,622	$ 24,142,484	$ 24,630,766
30	Contract Terminations, Market ($)	$ -	$ -	$ -	$ -	$ -
32	**Total LT & IT Purchases, Market ($)**	**$ 113,982,647**	**$ 117,483,425**	**$ 119,941,752**	**$ 122,358,578**	**$ 124,833,280**
35	Base Case LT & IT Sales for Resale ($)	$ 53,922,485	$ 55,578,395	$ 56,741,367	$ 57,884,705	$ 59,055,423
36	New Resource Total Firm Sales for Resale ($)	$ 101,738,105	$ 104,864,535	$ 107,058,814	$ 109,216,049	$ 111,424,942
37	**Total LT & IT Sales for Resale $**	**$ 155,660,590**	**$ 160,442,930**	**$ 163,800,181**	**$ 167,100,754**	**$ 170,480,365**

TABLE A - AVISTA
Appendix G

	C	D	E	F	G	H
3	**Avista Utilities**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	1,860,562	1,860,562	1,860,562	1,860,562	1,860,562
42	Cumulative CSL Load Growth (MWh)	530,262	824,393	1,015,094	1,263,954	1,561,535
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**2,390,824**	**2,684,955**	**2,875,656**	**3,124,516**	**3,422,097**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	711,667	711,667	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	711,667	711,667	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**0**	0	0	0	0
48	Cumulative Net New Resources (MWh)	**0**	**0**	**0**	**0**	**0**
49	**Total ST Purchases (MWh)**	**2,390,824**	**2,684,955**	**2,875,656**	**3,124,516**	**3,422,097**
50						
51						
52	New ST Sales for Resale (MWh)	-	-	-	-	-
53	Base ST Sales for Resale (MWh)	1,765,675	1,765,675	1,765,675	1,765,675	1,765,675
54	**Total ST Sales for Resale (MWh)**	**1,765,675**	**1,765,675**	**1,765,675**	**1,765,675**	**1,765,675**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	2,390,824	2,684,955	2,875,656	3,124,516	3,422,097
59	ST Purchase Power Price ($/MWh)	$ 52.49	$ 58.52	$ 60.27	$ 62.45	$ 64.69
60						
61	**Total ST Purchases ($)**	**$ 125,500,426**	**$ 157,136,951**	**$ 173,311,264**	**$ 195,131,911**	**$ 221,367,361**
62						
63	Total ST Sales for Resale (MWh)	1,765,675	1,765,675	1,765,675	1,765,675	1,765,675
64	ST Sales Power Price ($/MWh)	$ 48.17	$ 53.81	$ 55.41	$ 57.42	$ 59.47
65						
66	**Total ST Sales for Resale ($)**	**$ 85,047,603**	**$ 95,005,742**	**$ 97,835,925**	**$ 101,380,427**	**$ 105,009,807**
67						
68	**Price Spread (Plus/Minus, %)**	**4.20%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**58.52**	**60.27**	**62.45**	**64.69**
72	**Mid-Point Price ($/MWh)**		**56.17**	**57.84**	**59.93**	**62.08**
73	**Sales Prices ($/MWh)**		**53.81**	**55.41**	**57.42**	**59.47**
74						
75	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
76	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
77	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
78	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

TABLE B - FRANKLIN
Appendix G

	C	D	E	F	G	H
3	**PUD No. 1 of Franklin County**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
5	**Inflation Factor Date-to-Date**	**1.00000**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
6						
7						
8	**Total Purchased Power ($)**	**$ 50,153,483**	**$ 52,516,567**	**$ 54,728,000**	**$ 57,064,056**	**$ 59,525,586**
9	**Total Sale for Resale Credit ($)**	**$ 16,981,691**	**$ 18,970,060**	**$ 19,535,171**	**$ 20,242,911**	**$ 20,967,600**
10						
11						
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	1,131,609	1,131,609	1,131,609	1,131,609	1,131,609
14	New Resource LT & IT Purchased Power (MWh)	129,479				
15	LT & IT Terminated Contracts (MWh)					
16						
17	**Total LT & IT Purchased Power (MWh)**	**1,261,088**	**1,261,088**	**1,261,088**	**1,261,088**	**1,261,088**
18						
19						
20	Base Period LT & IT Sales for Resale (MWh)	-	-	-	-	-
21	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
23						
24	**Total LT & IT Sales for Resale (MWh)**	**-**	**-**	**-**	**-**	**-**
25						
26						
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 44,684,787	$ 46,057,016	$ 47,020,754	$ 47,968,222	$ 48,938,379
29	New Resource LT Purchases, Market ($)	$ -	$ -	$ -	$ -	$ -
30	Contract Terminations, Market ($)	$ -	$ -	$ -	$ -	$ -
31						
32	**Total LT & IT Purchases, Market ($)**	**$ 44,684,787**	**$ 46,057,016**	**$ 47,020,754**	**$ 47,968,222**	**$ 48,938,379**
33						
34						
35	Base Case LT & IT Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
36	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
37	**Total LT & IT Sales for Resale $**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
38						
39						

TABLE B - FRANKLIN
Appendix G

	C	D	E	F	G	H
3	**PUD No. 1 of Franklin County**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	82,227	82,227	82,227	82,227	82,227
42	Cumulative CSL Load Growth (MWh)	129,479	154,601	170,302	186,232	202,392
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**211,706**	**236,828**	**252,529**	**268,459**	**284,619**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	118,488	19,365	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**118,488**	19,365	0	0	0
48	Cumulative Net New Resources (MWh)	**118,488**	**137,853**	**137,853**	**137,853**	**137,853**
49	**Total ST Purchases (MWh)**	**93,218**	**98,975**	**114,677**	**130,606**	**146,766**
50						
51						
52	New ST Sales for Resale (MWh)	-	-	-	-	-
53	Base ST Sales for Resale (MWh)	271,537	271,537	271,537	271,537	271,537
54	**Total ST Sales for Resale (MWh)**	**271,537**	**271,537**	**271,537**	**271,537**	**271,537**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	93,218	98,975	114,677	130,606	146,766
59	ST Purchase Power Price ($/MWh)	$ 58.67	$ 65.26	$ 67.21	$ 69.64	$ 72.14
60						
61	**Total ST Purchases ($)**	**$ 5,468,696**	**$ 6,459,550**	**$ 7,707,245**	**$ 9,095,833**	**$ 10,587,207**
62						
63	Total ST Sales for Resale (MWh)	271,537	271,537	271,537	271,537	271,537
64	ST Sales Power Price ($/MWh)	$ 62.54	$ 69.86	$ 71.94	$ 74.55	$ 77.22
65						
66	**Total ST Sales for Resale ($)**	**$ 16,981,691**	**$ 18,970,060**	**$ 19,535,171**	**$ 20,242,911**	**$ 20,967,600**
67						
68	**Price Spread (Plus/Minus, %)**	**-3.40%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**65.26**	**67.21**	**69.64**	**72.14**
72	**Mid-Point Price ($/MWh)**		**67.56**	**69.58**	**72.10**	**74.68**
73	**Sales Prices ($/MWh)**		**69.86**	**71.94**	**74.55**	**77.22**
74						
75	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
76	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
77	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
78	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

TABLE C - IDAHO POWER
Appendix G

	C	D	E	F	G	H
3	**IDAHO POWER COMPANY**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
5	**Inflation Factor Date-to-Date**	**1.01010**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
6						
7						
8	**Total Purchased Power ($)**	**$ 344,015,861**	**$ 405,052,045**	**$ 425,669,018**	**$ 452,770,287**	**$ 479,809,575**
9	**Total Sale for Resale Credit ($)**	**$ 141,300,682**	**$ 156,963,434**	**$ 161,546,016**	**$ 167,225,912**	**$ 173,041,822**
10						
11						
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	925,369	925,369	925,369	925,369	925,369
14	New Resource LT & IT Purchased Power (MWh)					
15	LT & IT Terminated Contracts (MWh)					
17	**Total LT & IT Purchased Power (MWh)**	**925,369**	**925,369**	**925,369**	**925,369**	**925,369**
18						
19						
20	Base Period LT & IT Sales for Resale (MWh)	126,314.00	126,314.00	126,314.00	126,314.00	126,314.00
21	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
24	**Total LT & IT Sales for Resale (MWh)**	**126,314**	**126,314**	**126,314**	**126,314**	**126,314**
25						
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 54,844,275	$ 56,528,493	$ 57,711,345	$ 58,874,229	$ 60,064,959
29	New Resource LT Purchases, Market ($)	$ -	$ -	$ -	$ -	$ -
30	Contract Terminations, Market ($)	$ -	$ -	$ -	$ -	$ -
31						
32	**Total LT & IT Purchases, Market ($)**	**$ 54,844,275**	**$ 56,528,493**	**$ 57,711,345**	**$ 58,874,229**	**$ 60,064,959**
34						
35	Base Case LT & IT Sales for Resale ($)	$ 10,210,758	$ 10,524,321	$ 10,744,542	$ 10,961,044	$ 11,182,731
36	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
37	**Total LT & IT Sales for Resale $**	**$ 10,210,758**	**$ 10,524,321**	**$ 10,744,542**	**$ 10,961,044**	**$ 11,182,731**

TABLE C - IDAHO POWER
Appendix G

	C	D	E	F	G	H
3	**IDAHO POWER COMPANY**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	4,270,595	4,270,595	4,270,595	4,270,595	4,270,595
42	Cumulative CSL Load Growth (MWh)	972,160	1,391,135	1,532,423	1,722,335	1,893,171
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**5,242,755**	**5,661,730**	**5,803,018**	**5,992,930**	**6,163,766**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	59,568	0	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**59,568**				
48	Cumulative Net New Resources (MWh)	**59,568**	**59,568**	**59,568**	**59,568**	**59,568**
49	**Total ST Purchases (MWh)**	**5,183,187**	**5,602,162**	**5,743,450**	**5,933,362**	**6,104,198**
50						
51						
52	New ST Sales for Resale (MWh)	-	-	-	-	-
53	Base ST Sales for Resale (MWh)	2,617,333	2,617,333	2,617,333	2,617,333	2,617,333
54	**Total ST Sales for Resale (MWh)**	**2,617,333**	**2,617,333**	**2,617,333**	**2,617,333**	**2,617,333**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	5,183,187	5,602,162	5,743,450	5,933,362	6,104,198
59	ST Purchase Power Price ($/MWh)	$ 55.79	$ 62.21	$ 64.07	$ 66.39	$ 68.76
60						
61	**Total ST Purchases ($)**	**$ 289,171,586**	**$ 348,523,552**	**$ 367,957,673**	**$ 393,896,058**	**$ 419,744,616**
62						
63	Total ST Sales for Resale (MWh)	2,617,333	2,617,333	2,617,333	2,617,333	2,617,333
64	ST Sales Power Price ($/MWh)	$ 50.09	$ 55.95	$ 57.62	$ 59.70	$ 61.84
65						
66	**Total ST Sales for Resale ($)**	**$ 131,089,923**	**$ 146,439,113**	**$ 150,801,474**	**$ 156,264,868**	**$ 161,859,091**
67						
68	**Price Spread (Plus/Minus, %)**	**5.30%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**62.21**	**64.07**	**66.39**	**68.76**
72	**Mid-Point Price ($/MWh)**		**59.08**	**60.84**	**63.05**	**65.30**
73	**Sales Prices ($/MWh)**		**55.95**	**57.62**	**59.70**	**61.84**
74						
75						
76	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
77	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
78	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
79	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

TABLE D - NORTHWESTERN
Appendix G

	C	D	E	F	G	H
3	**NorthWestern Energy**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
5	**Inflation Factor Date-to-Date**	**1.01010**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
6						
7						
8	**Total Purchased Power ($)**	**$ 369,176,016**	**$ 399,158,967**	**$ 413,924,209**	**$ 430,227,831**	**$ 447,254,145**
9	**Total Sale for Resale Credit ($)**	**$ 60,831,012**	**$ 67,953,654**	**$ 69,977,966**	**$ 72,513,201**	**$ 75,109,146**
10						
11						
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	5,154,333	5,154,333	5,154,333	5,154,333	5,154,333
14	New Resource LT & IT Purchased Power (MWh)					
15	LT & IT Terminated Contracts (MWh)					
17	**Total LT & IT Purchased Power (MWh)**	**5,154,333**	**5,154,333**	**5,154,333**	**5,154,333**	**5,154,333**
18						
19						
20	Base Period LT & IT Sales for Resale (MWh)	-	-	-	-	-
21	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
24	**Total LT & IT Sales for Resale (MWh)**	**-**	**-**	**-**	**-**	**-**
25						
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 234,567,907	$ 241,771,274	$ 246,830,311	$ 251,803,941	$ 256,896,674
29	New Resource LT Purchases, Market ($)	$ -	$ -	$ -	$ -	$ -
30	Contract Terminations, Market ($)	$ -	$ -	$ -	$ -	$ -
31						
32	**Total LT & IT Purchases, Market ($)**	**$ 234,567,907**	**$ 241,771,274**	**$ 246,830,311**	**$ 251,803,941**	**$ 256,896,674**
34						
35	Base Case LT & IT Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
36	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
37	**Total LT & IT Sales for Resale $**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

TABLE D - NORTHWESTERN
Appendix G

	C	D	E	F	G	H
3	NorthWestern Energy	Rate Period	2012	2013	2014	2015
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	2,366,997	2,366,997	2,366,997	2,366,997	2,366,997
42	Cumulative CSL Load Growth (MWh)	165,907	286,437	368,584	451,946	536,541
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**2,532,904**	**2,653,434**	**2,735,581**	**2,818,943**	**2,903,538**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	0	0	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**0**				
48	Cumulative Net New Resources (MWh)	**0**	**0**	**0**	**0**	**0**
49	**Total ST Purchases (MWh)**	**2,532,904**	**2,653,434**	**2,735,581**	**2,818,943**	**2,903,538**
50						
51						
52	New ST Sales for Resale (MWh)	-	-	-	-	-
53	Base ST Sales for Resale (MWh)	1,444,555	1,444,555	1,444,555	1,444,555	1,444,555
54	**Total ST Sales for Resale (MWh)**	**1,444,555**	**1,444,555**	**1,444,555**	**1,444,555**	**1,444,555**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	2,532,904	2,653,434	2,735,581	2,818,943	2,903,538
59	ST Purchase Power Price ($/MWh)	$ 53.14	$ 59.31	$ 61.08	$ 63.29	$ 65.56
60						
61	**Total ST Purchases ($)**	**$ 134,608,109**	**$ 157,387,693**	**$ 167,093,898**	**$ 178,423,890**	**$ 190,357,471**
62						
63	Total ST Sales for Resale (MWh)	1,444,555	1,444,555	1,444,555	1,444,555	1,444,555
64	ST Sales Power Price ($/MWh)	$ 42.11	$ 47.04	$ 48.44	$ 50.20	$ 51.99
65						
66	**Total ST Sales for Resale ($)**	**$ 60,831,012**	**$ 67,953,654**	**$ 69,977,966**	**$ 72,513,201**	**$ 75,109,146**
67						
68	**Price Spread (Plus/Minus, %)**	**11.54%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**59.31**	**61.08**	**63.29**	**65.56**
72	**Mid-Point Price ($/MWh)**		**53.18**	**54.76**	**56.75**	**58.78**
73	**Sales Prices ($/MWh)**		**47.04**	**48.44**	**50.20**	**51.99**
74						
75						
76	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
77	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
78	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
79	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

TABLE E - PAC
Appendix G

	C	D	E	F	G	H
3	**PacifiCorp**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
5	**Inflation Factor Date-to-Date**	**1.01010**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
6						
7						
8	**Total Purchased Power ($)**	**$ 257,764,764**	**$ 265,680,485**	**$ 272,361,968**	**$ 340,665,453**	**$ 414,897,944**
9	**Total Sale for Resale Credit ($)**	**$ 407,202,338**	**$ 418,893,408**	**$ 411,939,133**	**$ 425,168,793**	**$ 438,715,257**
10						
11						
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	4,881,360	4,881,360	4,881,360	4,881,360	4,881,360
14	New Resource LT & IT Purchased Power (MWh)					
15	LT & IT Terminated Contracts (MWh)					
16						
17	**Total LT & IT Purchased Power (MWh)**	**4,881,360**	**4,881,360**	**4,881,360**	**4,881,360**	**4,881,360**
18						
19						
20	Base Period LT & IT Sales for Resale (MWh)	1,987,006.16	1,987,006.16	1,987,006.16	1,987,006.16	1,987,006.16
21	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
23						
24	**Total LT & IT Sales for Resale (MWh)**	**1,987,006**	**1,987,006**	**1,987,006**	**1,987,006**	**1,987,006**
25						
26						
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 257,764,764	$ 265,680,485	$ 271,239,820	$ 276,705,301	$ 282,301,664
29	New Resource LT Purchases, Market ($)	$ -	$ -	$ -	$ -	$ -
30	Contract Terminations, Market ($)	$ -	$ -	$ -	$ -	$ -
31						
32	**Total LT & IT Purchases, Market ($)**	**$ 257,764,764**	**$ 265,680,485**	**$ 271,239,820**	**$ 276,705,301**	**$ 282,301,664**
33						
34						
35	Base Case LT & IT Sales for Resale ($)	$ 100,150,215	$ 103,225,737	$ 105,385,724	$ 107,509,246	$ 109,683,619
36	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
37	**Total LT & IT Sales for Resale $**	**$ 100,150,215**	**$ 103,225,737**	**$ 105,385,724**	**$ 107,509,246**	**$ 109,683,619**
38						
39						

TABLE E - PAC
Appendix G

	C	D	E	F	G	H
3	**PacifiCorp**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	602,534	602,534	602,534	602,534	602,534
42	Cumulative CSL Load Growth (MWh)	863,260	1,209,002	1,441,003	1,910,872	2,390,139
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**1,465,794**	**1,811,536**	**2,043,537**	**2,513,407**	**2,992,673**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	2,034,837	0	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**2,034,837**	0	0	0	0
48	Cumulative Net New Resources (MWh)	**2,034,837**	**2,034,837**	**2,034,837**	**2,034,837**	**2,034,837**
49	**Total ST Purchases (MWh)**	**-**	**-**	**8,700**	**478,570**	**957,837**
50						
51						
52	New ST Sales for Resale (MWh)	**569,043**	**223,301**	**-**	**-**	**-**
53	Base ST Sales for Resale (MWh)	4,153,012	3,919,927	3,696,626	3,696,626	3,696,626
54	**Total ST Sales for Resale (MWh)**	**4,722,055**	**4,143,228**	**3,696,626**	**3,696,626**	**3,696,626**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	-	-	8,700	478,570	957,837
59	ST Purchase Power Price ($/MWh)	$ 112.12	$ 125.24	$ 128.98	$ 133.65	$ 138.43
60						
61	**Total ST Purchases ($)**	**$ -**	**$ -**	**$ 1,122,148**	**$ 63,960,152**	**$ 132,596,280**
62						
63	Total ST Sales for Resale (MWh)	4,265,669	3,919,927	3,696,626	3,696,626	3,696,626
64	ST Sales Power Price ($/MWh)	$ 71.98	$ 80.53	$ 82.93	$ 85.93	$ 89.01
65						
66	**Total ST Sales for Resale ($)**	**$ 307,052,124**	**$ 315,667,672**	**$ 306,553,410**	**$ 317,659,547**	**$ 329,031,638**
67						
68	**Price Spread (Plus/Minus, %)**	**21.73%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**125.24**	**128.98**	**133.65**	**138.43**
72	**Mid-Point Price ($/MWh)**		**102.89**	**105.95**	**109.79**	**113.72**
73	**Sales Prices ($/MWh)**		**80.53**	**82.93**	**85.93**	**89.01**
74						
75						
76	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
77	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
78	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
79	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

TABLE F - PGE
Appendix G

	C	D	E	F	G	H
3	**Portland General Electric**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
5	**Inflation Factor Date-to-Date**	**1.00000**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
6						
7						
8	**Total Purchased Power ($)**	**$ 995,599,274**	**$ 1,109,092,367**	**$ 1,161,805,198**	**$ 1,226,660,093**	**$ 1,293,854,321**
9	**Total Sale for Resale Credit ($)**	**$ 661,996,458**	**$ 738,682,742**	**$ 760,600,408**	**$ 787,994,399**	**$ 816,044,380**
10						
11						
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	5,421,414	5,421,414	5,421,414	5,421,414	5,421,414
14	New Resource LT & IT Purchased Power (MWh)					
15	LT & IT Terminated Contracts (MWh)					
16						
17	**Total LT & IT Purchased Power (MWh)**	**5,421,414**	**5,421,414**	**5,421,414**	**5,421,414**	**5,421,414**
18						
19						
20	Base Period LT & IT Sales for Resale (MWh)	83,050.00	83,050.00	83,050.00	83,050.00	83,050.00
21	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
23						
24	**Total LT & IT Sales for Resale (MWh)**	**83,050**	**83,050**	**83,050**	**83,050**	**83,050**
25						
26						
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 169,692,290	$ 174,903,386	$ 178,563,220	$ 182,161,268	$ 185,845,478
29	New Resource LT Purchases, Market ($)	$ -	$ -	$ -	$ -	$ -
30	Contract Terminations, Market ($)	$ -	$ -	$ -	$ -	$ -
31						
32	**Total LT & IT Purchases, Market ($)**	**$ 169,692,290**	**$ 174,903,386**	**$ 178,563,220**	**$ 182,161,268**	**$ 185,845,478**
33						
34						
35	Base Case LT & IT Sales for Resale ($)	$ 9,565,002	$ 9,858,735	$ 10,065,028	$ 10,267,838	$ 10,475,505
36	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
37	**Total LT & IT Sales for Resale $**	**$ 9,565,002**	**$ 9,858,735**	**$ 10,065,028**	**$ 10,267,838**	**$ 10,475,505**
38						
39						

TABLE F - PGE
Appendix G

	C	D	E	F	G	H
3	**Portland General Electric**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	15,769,455	15,769,455	15,769,455	15,769,455	15,769,455
42	Cumulative CSL Load Growth (MWh)	1,325,039	1,800,097	2,165,706	2,591,861	3,011,029
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**17,094,494**	**17,569,552**	**17,935,161**	**18,361,316**	**18,780,484**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	736,272	261,298	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**736,272**	261,298	0	0	0
48	Cumulative Net New Resources (MWh)	**736,272**	**997,569**	**997,569**	**997,569**	**997,569**
49	**Total ST Purchases (MWh)**	**16,358,223**	**16,571,983**	**16,937,592**	**17,363,747**	**17,782,915**
50						
51						
52	New ST Sales for Resale (MWh)	-	-	-	-	-
53	Base ST Sales for Resale (MWh)	12,928,925	12,928,925	12,928,925	12,928,925	12,928,925
54	**Total ST Sales for Resale (MWh)**	**12,928,925**	**12,928,925**	**12,928,925**	**12,928,925**	**12,928,925**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	16,358,223	16,571,983	16,937,592	17,363,747	17,782,915
59	ST Purchase Power Price ($/MWh)	$ 50.49	$ 56.37	$ 58.05	$ 60.15	$ 62.31
60						
61	**Total ST Purchases ($)**	**$ 825,906,984**	**$ 934,188,981**	**$ 983,241,978**	**$ 1,044,498,825**	**$ 1,108,008,842**
62						
63	Total ST Sales for Resale (MWh)	12,928,925	12,928,925	12,928,925	12,928,925	12,928,925
64	ST Sales Power Price ($/MWh)	$ 50.46	$ 56.37	$ 58.05	$ 60.15	$ 62.31
65						
66	**Total ST Sales for Resale ($)**	**$ 652,431,456**	**$ 728,824,008**	**$ 750,535,380**	**$ 777,726,561**	**$ 805,568,875**
67						
68	**Price Spread (Plus/Minus, %)**	**0.00%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**56.37**	**58.05**	**60.15**	**62.31**
72	**Mid-Point Price ($/MWh)**		**56.37**	**58.05**	**60.15**	**62.31**
73	**Sales Prices ($/MWh)**		**56.37**	**58.05**	**60.15**	**62.31**
74						
75						
76	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
77	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
78	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
79	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

TABLE G - PUGET SOUND ENERGY
Appendix G

	C	D	E	F	G	H
3	**Puget Sound Energy, Inc.**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
5	**Inflation Factor Date-to-Date**	**1.00000**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
6						
7						
8	**Total Purchased Power ($)**	**$ 984,963,518**	**$ 1,077,413,497**	**$ 1,130,522,015**	**$ 1,192,096,247**	**$ 1,257,771,331**
9	**Total Sale for Resale Credit ($)**	**$ 214,212,348**	**$ 239,260,021**	**$ 246,383,859**	**$ 255,303,404**	**$ 264,436,542**
10						
11						
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	9,353,824	9,353,824	9,353,824	9,353,824	9,353,824
14	New Resource LT & IT Purchased Power (MWh)	518,592				
15	LT & IT Terminated Contracts (MWh)					
16						
17	**Total LT & IT Purchased Power (MWh)**	**9,872,416**	**9,872,416**	**9,872,416**	**9,872,416**	**9,872,416**
18						
19						
20	Base Period LT & IT Sales for Resale (MWh)	7,810.00	7,810.00	7,810.00	7,810.00	7,810.00
21	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
23						
24	**Total LT & IT Sales for Resale (MWh)**	**7,810**	**7,810**	**7,810**	**7,810**	**7,810**
25						
26						
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 414,421,162	$ 427,147,660	$ 436,085,677	$ 444,872,802	$ 453,870,351
29	New Resource LT Purchases, Market ($)	$ 41,992,987	$ 43,283,439	$ 44,189,140	$ 45,079,551	$ 45,991,285
30	Contract Terminations, Market ($)	$ -	$ -	$ -	$ -	$ -
31						
32	**Total LT & IT Purchases, Market ($)**	**$ 456,414,150**	**$ 470,431,099**	**$ 480,274,817**	**$ 489,952,353**	**$ 499,861,636**
33						
34						
35	Base Case LT & IT Sales for Resale ($)	$ 396,370	$ 408,543	$ 417,091	$ 425,496	$ 434,101
36	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
37	**Total LT & IT Sales for Resale $**	**$ 396,370**	**$ 408,543**	**$ 417,091**	**$ 425,496**	**$ 434,101**
38						
39						

TABLE G - PUGET SOUND ENERGY
Appendix G

	C	D	E	F	G	H
3	**Puget Sound Energy, Inc.**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	9,619,746	9,619,746	9,619,746	9,619,746	9,619,746
42	Cumulative CSL Load Growth (MWh)	1,449,569	2,105,268	2,519,730	2,969,824	3,439,482
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**11,069,315**	**11,725,014**	**12,139,476**	**12,589,570**	**13,059,228**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	1,074,481	363,239	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**1,074,481**	363,239	0	0	0
48	Cumulative Net New Resources (MWh)	**1,074,481**	**1,437,719**	**1,437,719**	**1,437,719**	**1,437,719**
49	**Total ST Purchases (MWh)**	**9,994,834**	**10,287,294**	**10,701,756**	**11,151,850**	**11,621,509**
50						
51						
52	New ST Sales for Resale (MWh)	-	-	-	-	-
53	Base ST Sales for Resale (MWh)	4,422,562	4,422,562	4,422,562	4,422,562	4,422,562
54	**Total ST Sales for Resale (MWh)**	**4,422,562**	**4,422,562**	**4,422,562**	**4,422,562**	**4,422,562**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	9,994,834	10,287,294	10,701,756	11,151,850	11,621,509
59	ST Purchase Power Price ($/MWh)	$ 52.88	$ 59.00	$ 60.76	$ 62.96	$ 65.22
60						
61	**Total ST Purchases ($)**	**$ 528,549,368**	**$ 606,982,398**	**$ 650,247,198**	**$ 702,143,894**	**$ 757,909,696**
62						
63	Total ST Sales for Resale (MWh)	4,422,562	4,422,562	4,422,562	4,422,562	4,422,562
64	ST Sales Power Price ($/MWh)	$ 48.35	$ 54.01	$ 55.62	$ 57.63	$ 59.69
65						
66	**Total ST Sales for Resale ($)**	**$ 213,815,978**	**$ 238,851,478**	**$ 245,966,767**	**$ 254,877,909**	**$ 264,002,441**
67						
68	**Price Spread (Plus/Minus, %)**	**4.42%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**59.00**	**60.76**	**62.96**	**65.22**
72	**Mid-Point Price ($/MWh)**		**56.51**	**58.19**	**60.30**	**62.46**
73	**Sales Prices ($/MWh)**		**54.01**	**55.62**	**57.63**	**59.69**
74						
75						
76	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
77	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
78	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
79	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

TABLE H - SNOHOMISH
Appendix G

	C	D	E	F	G	H
3	**Snohomish PUD**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
5	**Inflation Factor Date-to-Date**	**1.00000**	**1.01030**	**1.02092**	**1.02015**	**1.02022**
6						
7						
8	**Total Purchased Power ($)**	**$ 312,018,163**	**$ 340,759,644**	**$ 353,235,418**	**$ 366,048,486**	**$ 379,524,945**
9	**Total Sale for Resale Credit ($)**	**$ 65,199,332**	**$ 72,833,457**	**$ 75,003,137**	**$ 77,720,429**	**$ 80,502,791**
10						
11						
12	**CALCULATION OF LT & IT PURCHASED POWER MWh and LT & IT Sales for Resale MWh**					
13	Base Period LT & IT Purchased Power (MWh)	7,693,114	7,693,114	7,693,114	7,693,114	7,693,114
14	New Resource LT & IT Purchased Power (MWh)	666,025				
15	LT & IT Terminated Contracts (MWh)	(219,600)				
16						
17	**Total LT & IT Purchased Power (MWh)**	**8,139,539**	**8,139,539**	**8,139,539**	**8,139,539**	**8,139,539**
18						
19						
20	Base Period LT & IT Sales for Resale (MWh)	-	-	-	-	-
21	New Resource LT & IT Sales for Resale (MWh)	-	-	-	-	-
22	LT & IT Terminated Contracts (MWh)	-	-	-	-	-
23						
24	**Total LT & IT Sales for Resale (MWh)**	**-**	**-**	**-**	**-**	**-**
25						
26						
27	**CALCULATION OF LT & IT PURCHASED POWER $ and LT & IT Sales for Resale $**					
28	Base Case LT & IT Purchased Power, Market ($)	$ 244,476,410	$ 251,984,059	$ 257,256,797	$ 262,440,521	$ 267,748,378
29	New Resource LT Purchases, Market ($)	$ 56,289,904	$ 58,019,703	$ 59,233,759	$ 60,427,319	$ 61,649,461
30	Contract Terminations, Market ($)	$ (22,995,000)	$ (22,995,000)	$ (22,995,000)	$ (22,995,000)	$ (22,995,000)
31						
32	**Total LT & IT Purchases, Market ($)**	**$ 277,771,314**	**$ 287,008,762**	**$ 293,495,556**	**$ 299,872,839**	**$ 306,402,839**
33						
34						
35	Base Case LT & IT Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
36	New Resource Total Firm Sales for Resale ($)	$ -	$ -	$ -	$ -	$ -
37	**Total LT & IT Sales for Resale $**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
38						
39						

TABLE H - SNOHOMISH
Appendix G

	C	D	E	F	G	H
3	**Snohomish PUD**	**Rate Period**	**2012**	**2013**	**2014**	**2015**
4						
40	**CALCULATION OF ST PURCHASED POWER MWh and ST Sales for Resale MWh**					
41	Base Period ST Purchased Power (MWh)	889,352	889,352	889,352	889,352	889,352
42	Cumulative CSL Load Growth (MWh)	288,201	440,087	508,665	573,091	639,745
43	**Base Short Term Purchases Plus Load Growth (MWh)**	**1,177,553**	**1,329,439**	**1,398,017**	**1,462,443**	**1,529,097**
44						
45	1/ & 2/ New Resource Total Annual Generation (MWh)	565,175	(100,850)	0	0	0
46	3/ & 4/ New Resource Total Firm Sales for Resale (MWh)	0	0	0	0	0
47	New Resource Less Firm Sales for Resale (MWh)	**565,175**	(100,850)	0	0	0
48	Cumulative Net New Resources (MWh)	**565,175**	**464,325**	**464,325**	**464,325**	**464,325**
49	**Total ST Purchases (MWh)**	**612,378**	**865,114**	**933,692**	**998,117**	**1,064,771**
50						
51						
52	New ST Sales for Resale (MWh)	-	-	-	-	-
53	Base ST Sales for Resale (MWh)	1,480,494	1,480,494	1,480,494	1,480,494	1,480,494
54	**Total ST Sales for Resale (MWh)**	**1,480,494**	**1,480,494**	**1,480,494**	**1,480,494**	**1,480,494**
55						
56						
57	**CALCULATION OF ST PURCHASED POWER $ and ST Sales for Resale $**					
58	Total ST Purchases (MWh)	612,378	865,114	933,692	998,117	1,064,771
59	ST Purchase Power Price ($/MWh)	$ 55.92	$ 62.13	$ 63.98	$ 66.30	$ 68.67
60						
61	**Total ST Purchases ($)**	**$ 34,246,849**	**$ 53,750,883**	**$ 59,739,862**	**$ 66,175,647**	**$ 73,122,106**
62						
63	Total ST Sales for Resale (MWh)	1,480,494	1,480,494	1,480,494	1,480,494	1,480,494
64	ST Sales Power Price ($/MWh)	$ 44.04	$ 49.20	$ 50.66	$ 52.50	$ 54.38
65						
66	**Total ST Sales for Resale ($)**	**$ 65,199,332**	**$ 72,833,457**	**$ 75,003,137**	**$ 77,720,429**	**$ 80,502,791**
67						
68	**Price Spread (Plus/Minus, %)**	**11.62%**				
69						
70	**Fiscal Year Purchase/Sales Prices**		**2012**	**2013**	**2014**	**2015**
71	**Purchase Prices ($/MWh)**		**62.13**	**63.98**	**66.30**	**68.67**
72	**Mid-Point Price ($/MWh)**		**55.66**	**57.32**	**59.40**	**61.52**
73	**Sales Prices ($/MWh)**		**49.20**	**50.66**	**52.50**	**54.38**
74						
75						
76	1/ Rate Period Total new resource MWhs equals sum of all new resources MWHs prior to start of rate period plus 1/2 new resource MWhs during rate period					
77	2/ FY 2012 new resource MWhs equals 1/2 new resource MWhs added during rate period					
78	3/ Rate Period Total Sales for Resale MWh equals sum of all new resources sales for resale MWHs prior to start of rate period plus 1/2 new resource sales for resale MWhs during rate period					
79	4/ FY 2012 Sales for Resale MWh equals 1/2 of new resource sales for resale MWhs added during rate period					

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