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

2007 Supplemental Wholesale Power Rate Case
Final Proposal

FY 2002-2008 LOOKBACK STUDY

September 2008

WP-07-FS-BPA-08

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FY 2002-2008 LOOKBACK STUDY

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COMMONLY USED ACRONYMS

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

DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatt-hour
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party
JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and

	Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities

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

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

MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection

POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PS	Power Services
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
TS	Transmission Services
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation

USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

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LOOKBACK STUDY

1.1 Overview of the Study

The FY 2002-2008 Lookback Study and FY 2002-2008 Lookback Documentation present the implementation of BPA's response to the remand order of the United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) concerning BPA's WP-02 rates as described in the Final ROD. Three related opinions require BPA to correct past (FY 2002-2008) and current (FY 2009) errors in the allocation of costs included in BPA's wholesale power rates to certain customers. In *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), the Court held that BPA's WP-02 power rates had improperly allocated the costs of the 2000 Residential Exchange Program Settlement Agreements (REP Settlement Agreements), as amended, to BPA's preference customers. This Study refers to the original REP Settlement Agreements and their associated amendments as the REP settlements. Because the Court held that BPA's allocation of REP settlement costs in the WP-02 rates was improper, and because the REP settlement costs are treated the same way in the WP-07 rates, BPA knows that the allocation of such costs in the WP-07 rates is similarly flawed.

In addition, in *Golden NW* the Court held that BPA's WP-02 fish and wildlife cost estimates, and by extension the rates set pursuant to those estimates, were not supported by substantial evidence. The Court indicated BPA had relied on outdated assumptions and had not appropriately considered information presented to it regarding its fish and wildlife costs. BPA's approach to addressing fish and wildlife costs for the WP-07 rates does not suffer the same flaws identified by the Court in the WP-02 rates. Nonetheless, BPA is taking steps to ensure that its Supplemental Proposal rates for FY 2009 are based on the most recent projections of fish and wildlife costs that reflect the information available at the time of rate development.

In a companion case, the Court held that BPA's REP Settlement Agreements with the IOUs were contrary to the Northwest Power Act. *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*). Subsequent to the *Golden NW* and *PGE* decisions, the Court ruled on three petitions for review challenging related Load Reduction Agreements (LRAs) BPA executed with two IOUs during the energy crisis of 2000-2001. The Court dismissed two of the petitions for lack of jurisdiction and one petition as moot. The Court also reviewed challenges to amendments to the REP Settlement Agreements adopted in 2004. In *Public Utility Dist. No. 1 of Snohomish County, Wash. v. Bonneville Power Admin.*, 506 F.3d 1145 (9th Cir. 2007) (*Snohomish*), the Court remanded the amendments and a contract provision establishing a "Reduction of Risk" discount to BPA.

The Lookback Study presents BPA's reform of its WP-02 and WP-07 rates to be consistent with the Court's direction. In doing so, BPA has decided that the actual rates charged consumer-owned utilities (COUs) between October 1, 2001, and September 30, 2008, would **not** be recalculated and revised bills would not be issued. Rather, BPA determined that the amount of REP benefits overpaid to IOUs would be identified and returned to preference customers through the various means explained in this Study.

The Residential Exchange Program (REP) was established through section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839, *et seq.* Section 5(c) provides that

> Whenever a Pacific Northwest electric utility offers to sell electric power to the Administrator at the average system cost of that utility's resources in each year, the Administrator shall acquire by purchase such power and shall offer, in exchange, to sell an equivalent amount of electric power to such utility for resale to that utility's residential users within the region.

16 U.S.C. § 839c(c)(1). Further, section 7(b)(1) provides that

> The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 5(c).

16 U.S.C. § 839e(b)(1). This provision identifies that the rates to be paid by exchanging utilities for the power purchased from BPA be the same as those paid by preference customers. However, section 7(b)(3) provides that the rates paid by exchanging utilities may be modified by the effects of the rate protection provided to preference customers by section 7(b)(2). BPA identifies the rate applicable to purchases from BPA under the REP as the Priority Firm Power (PF) Exchange rate.

Section 5(c)(1) provides that the rates paid by BPA for the power purchased from exchanging utilities under the REP is their average system cost (ASC) developed according to a methodology established consistent with section 5(c)(7). BPA developed its current ASC Methodology in 1984. The 1984 ASC Methodology sets forth the procedures used to determine each utility's ASC.

The REP, although couched in terms of a purchase and sale of power between BPA and the exchanging utility, can be reduced to a paper transaction because the amount of power purchased by BPA is equal to the amount of power purchased by the exchanging utility. *CP Nat'l Corp. v. BPA*, 928 F.2d 905, 907 (9th Cir. 1991). The transaction results in payments made at the difference between the utility's ASC and BPA's PF Exchange rate, multiplied by the eligible exchange load.

Therefore, in order to determine the amounts of REP payments to properly allocate to preference customers for the WP-02 and WP-07 rate periods, BPA must compute the ASCs and PF Exchange rates applicable to each period. The PF Exchange rate can be determined only after consideration of the section 7(b)(2) rate test. The Lookback Study sets forth BPA's calculations of each of the factors used in establishing REP payment amounts that would have occurred in the absence of the REP settlements.

Once the proper REP payment amounts are determined for FY 2002-2008, a comparison with the amounts paid under the REP settlements can be used to determine the amount overpaid to the IOUs and overcharged to the COUs. The Study then lays out the mechanism for recovering these overpayments and returning them to COUs.

1.2 Organization

The Lookback Study is divided into three parts following this introduction. These parts are: FY 2002-2006 Lookback; FY 2007-2008 Lookback; and Lookback Results. The FY 2002-2006 Lookback covers the period that the WP-02 rates were in effect. It sets forth BPA's calculations of an applicable PF Exchange rate that conforms to section 7(b) of the NPA and *Golden NW,* as well as ASCs and loads that generally conform to the 1984 ASC Methodology.

The 2007-2008 Lookback covers the first two years that the WP-07 rates, BPA's current rates, have been in effect. It sets forth BPA's calculations of an applicable PF Exchange rate that conforms to section 7(b) of the NPA, as well as ASCs that generally conform with the 1984 ASC Methodology.

Finally, the Lookback Results part brings together the results of the first two parts and presents the plan for the recovery of the amounts of overpayments from the IOUs under the REP settlements and their return to the COUs. The PF Exchange rates and ASCs are applied to eligible residential and small farm loads to compute the proper REP amounts for each year that are then compared to the amounts paid to IOUs under the REP settlement. Other factors, such as the application of deemer balances accrued by IOUs when their ASCs were less than the PF

Exchange rate, and the amounts received by IOUs under LRAs, are included in the comparison through the application of a set of rules. The results of these comparisons are the amounts overpaid to IOUs that need to be recovered and returned to PF customers. These overpayments to IOUs between October 2001 and March 2007 are called "Lookback Amounts." The total Lookback Amounts are determined for each IOU by accumulating annual amounts. The FY 2002-2008 Lookback Study also describes how BPA intends to recover the Lookback Amounts from the IOUs and return them to preference customers. The Lookback Study also describes additional overcharges paid by the COUs that were not paid to IOUs, covering the period April 2007 through September 2008, and how these overcharges will be repaid to COUs.

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PART ONE: FY 2002-2006 LOOKBACK

Chapter 1: FY 2002-2006 Introduction

Chapter 2: Load Resource Study

Chapter 3: Revenue Requirement

Chapter 4: Market Price Forecast

Chapter 5: Wholesale Power Rate Development Study, FY 2002-2006

Chapter 6: Section 7(b)(2) Rate Test, FY 2002-2006

Chapter 7: Backcast of IOU ASCs, FY 2002-2006

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1. FY 2002-2006 INTRODUCTION

Part One of the Lookback Study (FY 2002-2006) presents BPA's reform of the WP-02 rates to be consistent with the Court's direction. BPA has determined that the Court's remand to BPA can be satisfied by computing the amounts of REP Settlement costs overpaid to IOUs and inappropriately charged to preference customers. To calculate these amounts, BPA must determine the proper REP amounts to be allocated to PF preference rates. BPA has decided that the proper amounts can be calculated only after determining the appropriate PF Exchange rate for the period. Because the PF Exchange rate and ASCs determined in the WP-02 rate proceeding were so intertwined with assumptions regarding the REP Settlement Agreements, BPA decided that the WP-02 PF Exchange rate must be recalculated.

Part One sets forth the determination of the properly constructed PF Exchange rate for FY 2002-2006 after removing the effects of the REP Settlement Agreements. To do so, BPA "looks back" to 2001, when the final WP-02 rates were determined, and excises the REP Settlement Agreement assumptions from the rate calculations and replaces them with Residential Purchase and Sale Agreements (RPSAs) that conform to an REP consistent with sections 5(c) and 7(b).

The WP-02 rate proposal was conducted in three phases. First, in May 2000, BPA published its WP-02 Final Proposal, often called the May 2000 Proposal, that included a PF Exchange rate, and filed the proposal with the Federal Regulatory Energy Commission (FERC). Shortly thereafter, conditions arose that led BPA to conclude that the final rates were inadequate to assure cost recovery, and BPA requested that FERC stay review of the WP-02 Final Proposal. BPA then developed and published an Amended Rate Proposal in December 2000. Immediately thereafter, as financial prospects continued to deteriorate, BPA and customers began discussions that led to a settlement of issues that was incorporated into the WP-02 Supplemental Rate Proposal that was published in February 2001. This Supplemental Proposal added a set of three

Cost Recovery Adjustment Clauses (CRACs) to the WP-02 Final Proposal rates, and the revisions were adopted by the Administrator in June 2001 and submitted to FERC for review and confirmation. BPA did not perform the section 7(b)(2) rate test, and the PF Exchange rate was not recalculated in the WP-02 Supplemental Proposal because, in part, the IOUs had signed the REP Settlement Agreements by this time, and the CRACs adequately addressed REP-related cost recovery issues.

However, BPA has determined that absent the REP Settlement Agreements, the failure to redo the section 7(b)(2) rate test would have fatally compromised the June 2001 rate structure due to the impact of the changed conditions on the results of the rate test and the PF Exchange rate. Relying solely on CRACs when conditions had changed so radically would not have assured preference customers of the proper rate protection, nor would it have assured IOUs of the proper level of REP payments. Therefore, BPA has examined the major assumptions affecting the calculation of the PF Exchange rate at the time of the WP-02 Supplemental Proposal for the purpose of calculating a proper PF Exchange rate to be used in the Lookback analysis. The load forecast and revenue requirement were updated based on data available in the WP-02 Supplemental Proposal, as was the market price forecast. The market price forecast affected not only BPA rates, but ASC forecasts as well.

Also, whereas an important issue regarding the section 7(b)(2) rate test was mooted by conditions in the WP-02 Final Proposal, those conditions had changed by June 2001 so that the issue would have been decided at that time. Based on the record of the WP-02 proceeding, the Administrator has now decided that the Mid-Columbia resources included in the 7(b)(2)(D) resource stack were improperly included, and those resources are now removed. These changed assumptions are then incorporated into BPA's rate model as it existed at the conclusion of the WP-02 Supplemental Proposal stage of the WP-02 rate proceeding.

The following chapters set forth the changes to the rate models and the inputs used to recompute the PF Exchange rate for the FY 2002-2006 period. However, this newly calculated PF Exchange rate is necessary but not sufficient to fully incorporate the removal of the REP settlements from the rates calculations. The rates also included CRACs that changed rate levels throughout the rate period, and the REP settlements affected the CRAC results. Therefore, the REP settlement impacts on the CRACs have also been removed through a simplified process described in this study. The “reformed” CRACs are then applied to achieve the final PF Exchange rate used in this Lookback Study.

In addition to the PF Exchange rate, the ASCs for each IOU must be determined. Because the REP Settlement Agreements had attempted to settle disputes regarding various aspects of the REP, ASCs were not filed during the 2002-2006 Lookback period. As a substitute, BPA has incorporated FERC Form 1 data into the ASC determination model in a manner consistent with the 1984 ASC Methodology and estimated the annual ASCs for each IOU for both rate setting purposes (re-forecasts) and REP implementation purposes (backcasts). These are also explained in this Lookback Study.

2. LOAD RESOURCE STUDY, FY 2002-2006

2.1 Load Forecast for FY 2002-2006

2.1.1 Public and Federal Agency Load Forecast for FY 2002-2006

BPA has used the load obligation forecasts for the public body and cooperative utilities and the Federal agencies (together referred to as "Public Agencies") as presented in the 2002 Supplemental Proposal Final Study (WP-02-FS-BPA-09, pages 2-8) for this Lookback Study.

2.1.2 DSI Load Forecast for FY 2002-2006

The DSI contractual amounts in the WP-02 Supplemental Proposal Final Study remain the basis for the forecast of sales to the DSIs. However, in this final Lookback Study BPA reflects adjustments for DSI Load Reduction Agreements (LRAs) between BPA and the DSIs that were executed by June 21, 2001. Table 2.1 lists for each year: (1) the original aMW amount BPA was contractually committed to serve DSI customers; (2) the total aMW amount of DSI LRAs executed by June 21, 2001; and (3) the revised DSI sales forecast (the difference between the original contract amount and the DSI LRAs executed by June 21, 2001). DSI LRAs executed after June 21, 2001 are not considered in the DSI load forecast and therefore are not reflected in Table 2.1.

Table 2.1
Revised DSI Sales Forecast and DSI Load Reduction Amounts (aMW)

	WP-02 Supplemental Proposed Final Study DSI Sales Forecast	Total DSI Load Reduction Amounts Executed by June 21, 2001	Revised DSI Sales Forecast
FY 2002	1,440	804	636
FY 2003	1,440	556	884
FY 2004	1,440	51	1,389
FY 2005	1,440	51	1,389
FY 2006	1,440	44	1,396

Table 2.2
Comparison of Public and Federal Agency Sales Obligation Forecasts
annual average megawatts

	WP-02 Final Proposal	**Lookback Study Forecast***
FY 2002	4,130	5,728
FY 2003	4,221	5,776
FY 2004	4,335	5,823
FY 2005	4,414	5,870
FY 2006	4,602	5,938
5-Year Average	4,340	5,827

* (including about 1,600 aMW of Slice)

2.1.3 IOU Load Forecast for FY 2002-2006

In the WP-02 Final Proposal, BPA assumed 1,000 aMW of sales to the IOUs as established in the REP Settlement Agreements. Absent the REP settlements, there would have been no firm power sales to the IOUs at the RL rate. Hence, there is no forecast for sales of power at the RL rate included in the Lookback analysis.

2.2 Federal System Resources for FY 2002-2006

The resources and contract purchase estimates for the Lookback Study are identical to the WP-02 Final Proposal, except for any updates to the Federal system augmentation purchase estimates. These updates were not performed in the Load Resource Study. Rather, these changes are incorporated in the Rate Analysis Model (RAM), described in this Study, Chapter 5.

3. REVENUE REQUIREMENT, FY 2002-2006

3.1 Purpose of the Generation Revenue Requirement

The purpose of this chapter is to establish the level of revenues from wholesale power rates that, in retrospect, would have been necessary to recover, in accordance with sound business principles, the Federal Columbia River Power System (FCRPS) costs associated with the production, acquisition, marketing, and conservation of electric power assuming that BPA had recalculated base rates in the WP-02 Supplemental Proposal. The generation revenue requirement includes: recovery of the Federal investment in hydro generation, fish and wildlife, and conservation costs; Federal agencies' operations and maintenance (O&M) expenses allocated to power; capitalized contract expenses associated with non-Federal power suppliers such as Energy Northwest (EN); other power purchase expenses, such as short-term power purchases; power marketing expenses; cost of transmission services necessary for the sale and delivery of FCRPS power; and all other generation-related costs incurred by the Administrator pursuant to law.

3.2 Spending Level Development

3.2.1 Development Process for Spending Levels in the WP 02 Rate Case

The development of spending levels reflected in the WP-02 Supplemental Proposal revenue requirement was largely driven by the Regional Cost Review (Cost Review), a review of FCRPS costs launched jointly, in September 1997, by BPA and the Northwest Power and Conservation Council (NPCC). The result of the Cost Review was a set of recommendations to reduce the costs of BPA's commercial operations and constrain the costs of its public benefit programs. The Cost Review was built on the earlier Comprehensive Regional Review (Comprehensive Review), which envisioned a dramatically shrinking role for BPA. Both the Comprehensive

Review and the Cost Review are described in the WP-02 Revenue Requirement Study, WP-02-FS-BPA-02, chapter 2.

3.2.2 Adjustments to Program Expenses Used in the WP 02 Rate Proceeding for the Lookback

The forecasts of program expenses used in the WP-02 Supplemental Proposal have not been changed for this proceeding. The program expense assumptions used in the WP-02 Final Proposal were the only complete set of program expense forecasts available during the WP-02 Supplemental Proposal proceeding.

3.2.3 Capital Funding

FCRPS capital investments include Army Corps of Engineer (COE), Bureau of Reclamation (Reclamation), and BPA capital investments and third-party resource investments for which debt is secured by BPA (capitalized contracts). The WP-02 Final Proposal FCRPS capital outlay projections were $1,399 million for the FY 2002-2006 rate period. With the exception of the following items, these investment projects were not adjusted as part of the Lookback process.

Two capital investment assumptions important to the revenue requirement study and repayment study would have been updated if BPA had revised power base rates in the WP-02 Supplemental Proposal. These updates are reflected in this Supplemental Proposal. First, the WP-02 Supplemental Proposal did not include a forecast of capital spending for the Conservation Augmentation (ConAug) program. The program was created in 2000 to aid in meeting BPA's power augmentation needs. A forecast of ConAug capital investment, totaling $300 million for the FY 2002-2006 rate period, was available near the end of the WP-02 Supplemental Proposal process. If the revenue requirement study had been revised, that forecast would have been used in the determination of associated annual costs to replace the rough estimates of potential

ConAug expenses that had been included in WP-02 rate development. Second, the plant-in-service forecast for the Columbia River Fish Mitigation (CRFM) project had changed by the end of the WP-02 Supplemental Proposal process and would have been used if the revenue requirement study had been revised. The new forecast lowered CRFM capital investment by approximately $225 million beginning in FY 2001 through the FY 2002-2006 rate period.

In addition, the WP-02 Final Proposal included projected investments for FY 2000. At the time of the WP-02 Supplemental Proposal, the actual investments for FY 2000 were known. In cases where the actual results for FY 2000 differed from the forecast, the forecasted investments and plant-in-service dates were modified to determine interest expense and depreciation/amortization expense.

3.3 Generation Revenue Requirement

For each year of a rate test period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, PNRR, and if necessary, a Minimum Required Net Revenues component. The Statement of Cash Flows shows the analysis used to determine Minimum Required Net Revenues and the cash available for risk mitigation. The table formats and line descriptions in this chapter are consistent with those used in the WP-02 Supplemental Proposal. They are not the same formats and descriptions used in the WP-07 Supplemental Proposal.

The Income Statement (Table 3.1) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 16), Net Interest Expense (Line 24), Minimum Required Net Revenues (Line 26), and Planned Net Revenues for Risk (Line 27). The sum of these four major components is the Total Revenue Requirement (Line 29).

The amounts shown in Total Operating Expenses and Net Interest Expense are primarily established outside the rate setting process. The Minimum Required Net Revenues (Line 26) result from an analysis of the Statement of Cash Flow (Table 3.2). Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the power repayment studies and any other cash requirements, such as payment of irrigation assistance.

The Statement of Cash Flow analyzes annual cash inflows and outflows. Cash provided by Current Operations (Line 7), driven by the Non-Cash Expenses shown in Lines 4, 5, and 6, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 13) and Cash from Treasury Borrowing and Appropriations (Line 20). If cash provided by Current Operations is not sufficient, Minimum Required Net Revenues must be included in revenue requirements to accommodate the shortfall, yielding at least zero annual Increase in Cash (Line 21). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) is then incorporated in the Income Statement (Line 26).

3.3.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 3.1). Volume 1 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02B, provides additional information on the development and use of the data contained in the tables. Additional information on the development of data used in this Lookback process can be found in the FY 2002-2008 Lookback Documentation. WP-07-FS-BPA-08A, Section 3: Revenue Requirement.

O&M (Line 2). O&M represents FCRPS system O&M expenses incurred by the COE, Reclamation, U.S. Fish and Wildlife Service (USFWS), and BPA. Specific BPA O&M expenses include generation oversight, power scheduling (including upstream benefits), power marketing, Civil Service Retirement System pension expense, inter-business line expenses, administrative and support services, GTAs, and the costs of the NPPC. This line also includes payments to the Confederated Tribes of the Colville Reservation as called for under the Colville Settlement Act.

Short-Term Power Purchases (Line 4). Short-term purchases of power and off-system storage services are made to provide operational flexibility, displace higher-cost purchases, and augment the system output to serve Subscription loads. System augmentation purchases are made to achieve load/resource balance on an annual basis. Balancing power purchases are made to achieve load/resource balance on an hourly, daily, and monthly basis. *See* Volume 1, Chapter 4 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A; and WPRDS, WP-02-FS-BPA-05.

Long-Term Power Purchases (Line 5). Long-term power purchases are acquisitions of cost-effective resources intended to meet BPA's load obligations. These long-term commitments include the Idaho Falls and Cowlitz Falls hydroelectric projects, the billing credits and competitive acquisitions programs, and renewable resources such as wind and geothermal resource development. *See* Volume 1, Chapter 4 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Trojan (Line 6). Through net-billing arrangements, BPA has acquired Eugene Water and Electric Board's (EWEB) 30 percent ownership share of the now-terminated Trojan Nuclear Project. BPA's cost includes EWEB's share of Trojan phase-down, decommissioning costs, EWEB's debt service, and other Trojan-related costs. EWEB's other Trojan-related costs include contributions in lieu of taxes and EWEB's direct costs. *See* Volume 1, Chapters 4 and 10 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

WNP-1, -2, and - 3 (Lines 7, 8 and 9). Through project and net-billing agreements with Energy Northwest and BPA preference customer participants, and through exchange agreements with IOUs, BPA has acquired 100 percent of the capability of WNP-1 and -2 (now known as Columbia Generating Station, CGS) and 70 percent of the capability of WNP-3. Under a settlement agreement, BPA has certain rights to and obligations for the IOUs' 30 percent share of WNP-3.

BPA is obligated to fund all cash requirements associated with its share of these projects. These cash requirements include debt service and legal costs for WNP-1; debt service, operating, decommissioning, and capital costs for WNP-2; and debt service, 70 percent of preservation, and IOU settlement costs for WNP-3. IOU settlement costs for WNP-3 include the remaining 30 percent of preservation costs for that project.

Debt service costs include interest on outstanding Energy Northwest bonds, retirement of bonds according to schedules in each bond issue, and a reserve and contingency amount equal to 10 percent of the annual interest and retirement of bonds, less investment income on various accounts (Bond Fund Reserve Account, Bond Fund Interest Account, Reserve and Contingency Fund, Bond Fund Principal Account, and Revenue Fund), and transfer of any prior year's surplus reserve and contingency. *See* Volume 1, Chapters 4 and 10 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Residential Exchange Program (Line 10). BPA's rate development methodology is based on the gross costs of the program; that is, the utilities' ASCs times their exchangeable loads.

BPA Fish and Wildlife O&M (Line 11). BPA funds projects designed to accomplish measures in the NPCC's Columbia River Basin Fish and Wildlife Program and the 1995 National Marine Fisheries Service (NMFS) Biological Opinion, and to be consistent with the fish cost stabilization agreement. This line item includes the expense portion of BPA's Fish and Wildlife "direct" Program, including staff costs and operating expenses of fish and wildlife activities. These activities include measures to implement the NPCC's Fish and Wildlife Program and Biological Opinions issued by the NMFS and the USFWS. *See* Volume 1, Chapters 4 and 13 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Amortization of Fish and Wildlife Investment (Line 12). Amortization of Fish and Wildlife is the annual expense associated with the write-off of BPA capital investments in BPA's Fish and Wildlife Program. The annual write-off is calculated using the straight-line method of depreciation over an expected average life of 15 years. *See* Volume 1, Chapters 4 and 5 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Conservation (Line 13). The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. The competitive market situation is driving the need for alternatives to traditional approaches to developing conservation resources. BPA was transitioning from centralized BPA-funded programs to new customer-driven approaches. The costs shown here reflect BPA's participation with other regional entities supporting marketing transformation and development activities, as well as facilitating activities that meet the needs of customers and create business opportunities for the private sector. *See* Volume 1, Chapters 4 and 10 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Amortization of Conservation Investment (Line 14). Amortization of Conservation is the annual expense associated with the write-off of BPA's investments in energy conservation measures. The annual conservation write-off is calculated using the straight-line method of depreciation over an expected life of 20 years. *See* Volume 1, Chapters 4 and 5 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A. This line also includes the amortization of ConAug capital investments added as a part of the Lookback process. *See* Documentation, WP-07-FS-BPA-08A, Section 3: Revenue Requirement.

Federal Projects Depreciation (Line 15). Depreciation is the annual capital recovery expense associated with FCRPS plant-in-service. Reclamation and COE (including lower Snake River Fish and Wildlife Compensation Plan) plant, including assets for fish and wildlife recovery, is depreciated by the straight-line method of calculation, using the average service life of each project. Capital equipment (office furniture and fixtures and data processing hardware and software) is also depreciated by the straight-line method using the average service life for the categories of capital investment. *See* Volume 1, Chapters 4 and 5 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A. This line also includes adjustments to amortization associated with the use of a revised CRFM forecast. *See* Documentation, WP-07-FS-BPA-08A, Section 3: Revenue Requirement.

Total Operating Expenses (Line 16). Total Operating Expenses is the sum of the above expenses (Lines 2 through 15).

Interest Expense on Appropriated Funds (Line 19). Interest on Appropriated Funds includes interest on BPA, COE, and Reclamation appropriations as determined in the generation repayment studies. *See* Volume 1, Chapters 4, 6, and 9 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A. This line also includes adjustments to interest expense associated with the use of a revised CRFM forecast. *See* Documentation, WP-07-FS-BPA-08A, Section 3: Revenue Requirement.

Interest Expense on Long-Term Debt (Line 20). Interest on long-term debt includes interest on bonds that BPA issues to the U.S. Treasury to fund investments in capital equipment, conservation, fish and wildlife, and to fund Reclamation and COE investments under the Energy Policy Act of 1992 (EPA-92) (P.L. No. 102-486, 1992 U.S. Code Cong. & Admin. News, 106 Stat. 2776). Such interest expense is determined in the generation repayment studies. Any payments of premiums for bonds projected to be amortized are included in this line. Also included is an interest income credit calculated in the generation repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year.
See Volume 1, Chapters 4, 6, and 9 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A. This line also includes an increase to interest expense associated with the inclusion of ConAug investments. *See* Documentation, WP-07-FS-BPA-08A, Section 3: Revenue Requirement.

Interest Credit on Cash Reserves (Line 21). An interest income credit is also computed on the projected year-end cash balance in the BPA fund attributable to the Power function that carries over into the next year. It is credited against bond interest.

See Volume 1, Chapter 6 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Capitalization Adjustment (Line 22). Implementation of the Refinancing Act entailed a change in capitalization on BPA's financial statements. Outstanding appropriations were reduced as a result of the refinancing by $2,142 million in the generation function. The reduction is recognized annually over the remaining repayment period of the refinanced appropriations. The annual recognition of this adjustment is based on the increase in annual interest expense resulting from implementation of the Refinancing Act, as shown in repayment studies for the year of the refinancing transaction (1997). The capitalization adjustment is included on the income statement as a non-cash, contra-expense. *See* Volume 1, Chapter 8 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Allowance for Funds Used During Construction (AFUDC) (Line 23). AFUDC is a credit against interest costs on long-term debt (Line 20). This reduction to interest costs reflects an estimate of interest on the funds used during the construction period of facilities that have yet to be placed in service. AFUDC is capitalized along with other construction costs and is recovered through rates over the expected service life of the related plant as part of the depreciation expense after the facilities are placed in service. AFUDC, which is calculated outside the generation repayment studies, is associated with the COE and Reclamation capital investments direct-funded by BPA. *See* Volume 1, Chapter 4 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Net Interest Expense (Line 24). Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 19), Interest on Long-Term Debt (Line 20), Interest Credit on Cash Reserves (Line 21), capitalization adjustment (Line 22), and AFUDC (Line 23).

Total Expenses (Line 25). Total Expenses are the sum of Total Operating Expenses (Line 16) and Net Interest Expense (Line 24).

Minimum Required Net Revenues (Line 26). Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 3.2), may be necessary to cover cash requirements in excess of accrued expenses. *See* Volume 1, Chapter 1 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Planned Net Revenues for Risk (Line 27). Planned Net Revenues for Risk are the amount of net revenues to be included in rates for financial risk mitigation. Planned net revenues for risk of $98 million per year (in addition to starting reserves, the cash flow when non-cash expenses exceed cash payments, the CRAC, and other risk mitigation tools) are available to mitigate risk in FY 2002-2006.

Total Planned Net Revenues (Line 28). Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 26) and Planned Net Revenues for Risk (Line 27).

Total Revenue Requirement (Line 29). Total Revenue Requirement is the sum of Total Expenses (Line 25) and Total Planned Net Revenues (Line 28).

3.3.2 Statement of Cash Flows

Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 3.2). Volumes 1 and 2 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A and WP-02-FS-BPA-02B, provide additional information related to the use and development of the data contained in table.

Minimum Required Net Revenues (Line 2). Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required Net Revenues may be necessary so that the cash provided from operations will be sufficient to cover the planned amortization and irrigation assistance payments (the difference between Lines 13 and 20) without causing the Annual Increase (Decrease) in Cash (Line 21) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 26).

Federal Projects Depreciation (Line 4). Depreciation is from the Income Statement (Table 3.1, Line 15). It is included in computing Cash Provided By Operations (Line 7) because it is a non-cash expense of the FCRPS.

Amortization of Conservation/Fish and Wildlife Investment (Line 5). Amortization of Conservation and Fish and Wildlife Investment is from the Income Statement (Table 3.1, Lines 12 and 14). Similar to Depreciation (Line 4), it is a non-cash expense.

Capitalization Adjustment (Line 6). Capitalization Adjustment is from the Income Statement (Table 3.1, Line 22). It is a non-cash (contra) expense. *See* Volume 1, Chapter 8 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Cash Provided By Current Operations (Line 7). Cash Provided By Current Operations, the sum of Lines 2, 4, 5, and 6, is available for the year to satisfy cash requirements.

Investment in Utility Plant (Line 10). Investment in Utility Plant represents the annual increase in additions to plant-in-service for COE, Reclamation, and BPA, including construction work-in-progress funded by bonds. *See* Volume 1, Chapter 5 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Investment in Conservation (Line 11). Investment in Conservation represents the annual increase in capital expenditures associated with Conservation programs. *See* Volume 1, Chapter 4 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Investment in Fish and Wildlife (Line 12). Investment in Fish and Wildlife represents the annual increase in BPA's capital expenditures to fund projects designed to comply with the NPCC's Columbia River Basin Fish and Wildlife Program and Biological Opinions issued by NMFS and USFWS. These amounts are consistent with the Principles. *See* Volume 1, Chapters 5 and 13 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Cash Used for Capital Investments (Line 13). Cash Used for Capital Investments is the sum of Lines 10, 11, and 12.

Increase in Long-Term Debt (Line 15). Increase in Long-Term Debt reflects the new bonds issued by BPA to the U.S. Treasury to fund capital equipment, conservation, and fish and wildlife capital programs and to direct-fund Reclamation and COE investments under the EPA-92. Also included in this amount are any notes issued to the U.S. Treasury. *See* Volume 1, Chapter 7 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Repayment of Long-Term Debt (Line 16). Repayment of Long-Term Debt is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury as determined in the generation repayment studies. *See* Volume 1 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Increase in Congressional Capital Appropriations (Line 17). Increase in Congressional Capital Appropriations represents Congressional appropriations projected to be received during the year for COE and Reclamation capital projects. *See* Volume 1, Chapter 5 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Repayment of Capital Appropriations (Line 18). Repayment of Capital Appropriations represents projected amortization of outstanding COE and Reclamation appropriations as determined in the generation repayment studies. *See* Volume 2 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02B.

Payment of Irrigation Assistance (Line 19). Payment of Irrigation Assistance represents the payment of appropriated capital construction costs of Reclamation irrigation facilities that have been determined to be beyond the ability of the irrigators to pay and allocated to generation revenues for repayment. *See* Volume 1, Chapter 10 of Documentation for Revenue Requirement Study, WP-02-FS-BPA-02A.

Cash From Treasury Borrowing and Appropriations (Line 20). Cash from Treasury Borrowing and Appropriations is the sum of Lines 15 through 19. This is the net cash flow resulting from increases in cash from new long-term debt and capital appropriations and decreases in cash from repayment of long-term debt and capital appropriations.

Annual Increase (Decrease) in Cash (Line 21). Annual Increase (Decrease) in Cash is the sum of Lines 7, 13, and 20 and reflects the annual net cash flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues would be insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease. *See* discussion above of Minimum Required Net Revenues (Line 2).

Planned Net Revenues for Risk (Line 22). Planned Net Revenues for Risk reflect the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 3.1, Line 27).

Total Annual Increase (Decrease) in Cash (Line 23). Total Annual Increase (Decrease) in Cash is the sum of Lines 21 and 22. It is the total annual cash that is projected to be available to add to BPA's cash reserves.

3.3.3 Revenue Test

In a typical rate proceeding, the revenue requirement study would demonstrate the continuing adequacy of existing rates must be tested annually, consistent with RA 6120.2. The revenue tests determine whether the revenues projected from current rates and from proposed rates will meet cost recovery requirements as well as the U.S. Treasury payment probability risk goal for the rate period. Since we are not recalculating rates for retroactive application, these tests of adequacy are not necessary.

Table 3.1

GENERATION REVENUE REQUIREMENT
INCOME STATEMENT
($000s)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	OPERATING EXPENSES:					
2	OPERATION & MAINTENANCE	469,614	453,220	446,510	441,161	438,260
3	PURCHASE AND EXCHANGE POWER-					
4	SHORT-TERM POWER PURCHASES	931,218	835,152	838,667	890,696	843,768
5	LONG-TERM POWER PURCHASES	65,904	66,159	66,450	66,977	67,414
6	TROJAN	19,547	14,154	12,564	12,589	12,609
7	WNP NO. 1	178,104	168,240	175,007	168,294	180,376
8	WNP NO. 2	351,536	408,804	404,348	361,649	391,800
9	WNP NO. 3	156,806	156,162	152,401	152,649	151,006
10	RESIDENTIAL EXCHANGE PROGRAM	0	0	0	0	0
11	BPA FISH & WILDLIFE O&M	131,700	138,000	140,100	142,900	144,400
12	AMORTIZATION OF BPA FISH & WILDLIFE INVESTMENT	18,899	20,969	22,864	24,521	25,533
13	CONSERVATION	34,929	33,340	33,640	34,040	34,340
14	AMORTIZATION OF BPA CONSERVATION INVESTMENT	61,163	60,126	58,108	64,161	73,650
15	FEDERAL PROJECTS DEPRECIATION	96,328	98,991	100,364	103,207	105,731
16	TOTAL OPERATING EXPENSES	2,515,746	2,453,316	2,451,023	2,462,844	2,468,886
17	INTEREST EXPENSE:					
18	INTEREST ON FEDERAL INVESTMENT-					
19	ON APPROPRIATED FUNDS	240,719	242,176	247,781	255,551	255,779
20	ON LONG-TERM DEBT	64,034	70,273	78,934	88,175	96,674
21	INTEREST CREDIT ON CASH RESERVES	(61,063)	(67,549)	(75,054)	(79,878)	(84,818)
22	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
23	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(2,992)	(2,890)	(2,050)	(2,056)	(2,044)
24	NET INTEREST EXPENSE	192,960	194,482	201,736	217,002	220,801
25	TOTAL EXPENSES	2,708,706	2,647,798	2,652,759	2,679,846	2,689,687
26	MINIMUM REQUIRED NET REVENUES 1/	0	0	0	998	0
27	PLANNED NET REVENUES FOR RISK	98,000	98,000	98,000	98,000	98,000
28	TOTAL PLANNED NET REVENUES (26+27)	98,000	98,000	98,000	98,998	98,000
29	**TOTAL REVENUE REQUIREMENT**	**2,806,706**	**2,745,798**	**2,750,759**	**2,778,844**	**2,787,687**

1/ SEE NOTE ON CASH FLOW TABLE.

Table 3.2

GENERATION REVENUE REQUIREMENT
STATEMENT OF CASH FLOWS
($000s)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	CASH FROM CURRENT OPERATIONS:					
2	MINIMUM REQUIRED NET REVENUES 1/	0	0	0	998	0
3	EXPENSES NOT REQUIRING CASH:					
4	FEDERAL PROJECTS DEPRECIATION	96,328	98,991	100,364	103,207	105,731
5	AMORTIZATION OF CONSERVATION/F&W INVESTMENT	80,062	81,095	80,972	88,682	99,183
6	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
7	CASH PROVIDED BY CURRENT OPERATIONS	128,652	132,558	133,461	148,097	160,124
8	CASH USED FOR CAPITAL INVESTMENTS:					
9	INVESTMENT IN:					
10	UTILITY PLANT	(228,000)	(168,700)	(297,500)	(185,525)	(220,225)
11	CONSERVATION	0	0	0	0	0
12	FISH & WILDLIFE	(34,732)	(38,317)	(35,825)	(33,988)	(34,182)
13	CASH USED FOR CAPITAL INVESTMENTS	(262,732)	(207,017)	(333,325)	(219,513)	(254,407)
14	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:					
15	INCREASE IN LONG-TERM DEBT	127,032	125,917	98,425	97,013	97,207
16	REPAYMENT OF LONG-TERM DEBT	(66,000)	(25,622)	(27,400)	(30,757)	0
17	INCREASE IN CONGRESSIONAL CAPITAL APPROPRIATIONS	135,700	81,100	234,900	122,500	157,200
18	REPAYMENT OF CAPITAL APPROPRIATIONS	(41,401)	(47,362)	(64,885)	(117,340)	(128,476)
19	PAYMENT OF IRRIGATION ASSISTANCE	0	0	(739)	0	0
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	155,331	134,033	240,301	71,416	125,931
21	ANNUAL INCREASE (DECREASE) IN CASH	21,251	59,574	40,437	0	31,648
22	PLANNED NET REVENUES FOR RISK	98,000	98,000	98,000	98,000	98,000
23	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	119,251	157,574	138,437	98,000	129,648

1/ Line 21 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

4. MARKET PRICE FORECAST, FY 2002-2006

4.1 Market Price Forecast for FY 2002-2006

BPA is not proposing any changes to the market price forecast from the WP-02 Supplemental Proposal, which was contained in the 2002 Supplemental Proposal Final Study (WP-02-FS-BPA-09). The results of this market price forecast are used in the Lookback analysis and are presented in Table 4.1.

Table 4.1
Flat Annual Market Price Forecast
($/MWh)

Year	Price
FY 2002	148.00
FY 2003	63.00
FY 2004	45.96
FY 2005	49.51
FY 2006	49.07

For more information, *see* Conger, *et al.*, WP-07-E-BPA-56.

5. WHOLESALE POWER RATE DEVELOPMENT STUDY, FY 2002-2006

5.1 Revised Forecasts of Average System Costs and Loads for FY 2002-2006

BPA made only one set of changes to the data inputs used in the WP-02 Final Proposal to revise the IOU ASC forecasts for the Lookback Study. These data changes updated the forward flat-block price forecasts, which were available from broker quotes in 2001. *See* Lookback Study Market Price Forecast, Chapter 4. The price forecast available in June 2001 for flat-block purchased power was 148 mills/kWh in 2002, declining to 63.00, 45.92, 49.46, and 49.02 mills/kWh for the following four years, respectively. For the years 2007 through 2010, a 2.5 percent annual growth rate to the 2006 price was assumed. A transmission adder of 2.63 mills/kWh, which is unchanged from the adder used in the WP-02 Final Proposal, was added to all years of the price forecast. The Excel-based ASC Forecast Model used in the WP-02 Final Proposal was updated with the revised market price forecasts.

Also changed was an important assumption in the WP-02 Final Proposal regarding "in lieu" transactions, whereby BPA acquires power from a cheaper resource in lieu of acquiring power from the exchanging utility at its ASC. In the WP-02 Final Proposal, BPA assumed it would in lieu 50 percent of the REP loads of Puget Sound Energy, Portland General Electric, and PacifiCorp's southern Idaho jurisdiction of its Utah Power (now Rocky Mountain Power) Division. Such transactions would have meant that BPA could buy actual power from another source at a price less than an exchanging utility's ASC, and could sell real power to the utility, effectively saving the difference between the ASC and the lower-cost power. As noted above, by June 2001, the forecast market quotes were showing prices significantly higher than forecast ASCs. Continuing to assume at that time that BPA would serve 50 percent (or any) of the exchanging utilities' loads with an in-lieu purchase at the market price was therefore no longer reasonable. BPA does not propose any in-lieu transactions for this Lookback Study.

Documentation Table 5.1.1 summarizes IOU ASC determinations from the WP-02 Final Proposal. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.1.1. This table also includes annual load-weighted ASCs.

Documentation Table 5.1.2 summarizes reforecast ASCs for NorthWestern Energy, PacifiCorp (both divisions), Portland General Electric and Puget Sound Energy, which were determined for this Lookback Study using the ASC Forecast model. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.1.2. ASC forecasts for Avista and Idaho Power were not based on the ASC Forecast model because base data for these utilities dated to the mid-1980s. Instead, estimated ASCs from the WP-02 Final Proposal are escalated as follows. Load-weighted reforecast ASCs are compared with the load-weighted results from Table 5.1.1, and show an increase in FY 2002 of 43.6 percent. This increase, and each subsequent annual increase, is used as a multiplier to determine reforecast ASCs for Avista and Idaho Power. For example, Avista's WP-02 Final Proposal ASC was estimated to be $29.25/MWh. Its revised ASC forecast for 2002 is calculated as $29.25 \times 1.436 = \$42.00$/MWh. Avista and Idaho Power reforecast ASCs are shown in the Lookback Study Documentation, Table 5.1.2.

A side-by-side comparison by year and company of WP-02 Final Proposal ASCs and the reforecast ASCs is found in the Lookback Study Documentation, Table 5.1.3.

Documentation Table 5.1.4 shows model inputs and outputs for Northwestern, PacifiCorp (separated by division), Portland General Electric, and Puget Sound Energy.

5.2 FY 2002-2006 Lookback Cost Allocation and Rate Design Implementation

5.2.1 Ratemaking Sequence

The base rate ratemaking sequence used in the FY 2002-2006 Lookback is the same as was used in the WP-02 WPRDS except that the Subscription Strategy section is no longer necessary. The FY 2002-2006 Lookback ratemaking includes a Cost of Service Analysis (COSA) and a series of Rate Design Step adjustments using the same set of RAM2002 models used in the WP-02 Final Proposal. These models provide a forecast of base rates for the FY 2002-2006 time period. In addition, a new Post-Processor model has been developed for this Supplemental Proposal to determine if a CRAC adjustment to base rates would have been required to recover BPA's power costs in that time period.

Although the COSA procedures and Rate Design Step adjustments that made up BPA's ratemaking in the WP-02 Final Proposal are used in this Lookback analysis for FY 2002-2006, much of the data used in the current calculations are different than those used for the WP-02 Final Proposal. BPA is using ratemaking information that was available in and around the spring of 2001 in this Lookback analysis. For a more detailed discussion of the data differences, *see* Ingram, *et al.*, WP-07-E-BPA-58.

The COSA assigns responsibility for BPA's revenue requirement to the various classes of service in accordance with generally accepted ratemaking principles and in compliance with statutory directives governing BPA's ratemaking. The Rate Design Step adjustments to the allocated costs in the COSA are necessary to assure that BPA recovers its test period costs while maintaining the statutory-based relationship between the rates paid by the different rate pools and to implement particular statutory rate directives of the Northwest Power Act.

5.2.2 Cost of Service Analysis (COSA)

The COSA allocates the test period generation revenue requirements that are determined in the Revenue Requirement Study, chapter 3, to BPA's customer classes. The COSA apportions or "allocates" the test period generation revenue requirements among classes of service based on the principle of cost causation. The relative use of resources, services, or facilities among customer classes is identified, and costs generally are allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

Four major ratemaking steps were completed in the process of determining BPA's total cost of service: (1) *functionalization* of costs between generation and transmission; (2) *segmentation* of costs of BPA's transmission system (not applicable in a power rate case); (3) *classification* of costs between demand, energy, and load variance; and (4) *allocation* of costs to classes of service.

In this FY 2002-2006 portion of the Lookback, BPA determined what the power rates charged by BPA would have been absent the IOU REP Settlement Agreements. Functionalization of costs between generation and transmission was performed in conjunction with the development of BPA's total revenue requirements, and only those costs associated with the Power function are included in BPA's power rates. The one exception is that the gross exchange resource costs are functionalized so that only the power portion is subject to the Rate Design Steps, and the transmission portion is then added back in after the Rate Design Steps are completed. The remaining steps to determine BPA's cost of service for wholesale power – classification and allocation of costs – are performed in the COSA. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Section 5.2.3, Tables 5.2.3.1 - 5.2.3.10.

5.2.3 Revenue Requirement

The Revenue Requirement Study, Section 3, is based on revenue and cost estimates for the five-year test period, FY 2002-2006. The generation revenue requirements from the Revenue Requirement Study are adjusted in the COSA for projected balancing purchase power costs, system augmentation costs, and the functionalization and classification of REP costs. For the five test years, the total adjusted generation revenue requirement is $16.843 billion. Adjusted annual functionalized revenue requirements used for rate calculations are shown in the Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 through 5.2.3.5 (COSA 06 FY 02 through COSA 06 FY 06). Total adjusted functionalized revenue requirements for the five-year period are shown in the Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.7 (COSA 08).

5.2.3.1 Functionalized Revenue Requirement

Power rates are set to recover only generation costs and transmission costs associated with the Power function. Transmission rates were set in a separate rate case and were not affected by the REP settlements. The COSA uses the revenue requirement for the generation component of the FCRPS. *See* Section 3.

5.2.3.2 Power Purchases in the COSA

Three categories of purchased power are shown in the COSA: (1) purchased power; (2) balancing power purchases; and (3) system augmentation.

5.2.3.2.1 Purchased Power

The purchased power costs reflect the acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs less the costs associated with the Idaho Falls and Cowlitz projects. Costs of purchased power from contracts from the early 1990s are included in the NR resource pool. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 through 5.2.3.5, (COSA 06 FY 2002 through COSA 06 FY 2006). Purchased power costs are unchanged from the WP-02 Final Proposal.

5.2.3.2.2 Balancing Power Purchases

Included in the costs of balancing power purchases are the costs of power purchases and storage required to meet firm deficits on a daily and monthly basis. Projected balancing power purchases are needed to serve firm loads at the margin in months other than the spring fish migration period. The expense estimate for balancing power purchases included in the revenue requirements is adjusted in the COSA as a result of Risk Analysis Model (RiskMod) modeling to reflect projected operation of the FCRPS. For this Lookback, the cost of balancing power purchases was not changed from the WP-02 Final Proposal. *See* Lookback Study Documentation, WP-02-FS-BPA-05A, Section 3.4. Costs of balancing power purchases are characterized as FBS replacements and as such are included in and allocated as FBS costs. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 through 5.2.3.5 (COSA 06 FY 2002 through COSA 06 FY 2006).

5.2.3.2.3 System Augmentation

BPA is also proposing to acquire resources beyond the inventory represented by the FBS and new resources. These acquisitions are defined as system augmentation costs in the COSA and are used to meet customer firm power loads in excess of firm Federal resources on an annual basis. System augmentation purchases are characterized as FBS replacements. The Federal system will be augmented using both long- and short-term power purchase contracts. System augmentation costs are shown in Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 through 5.2.3.5, and 5.2.3.7 (COSA 06 and COSA 08). The amount and cost of system augmentation have been modified to be consistent with load and market price changes for the Lookback.

5.2.3.2.4 Adjustments to Gross Residential Exchange Costs

BPA's revenue requirement includes the gross cost of the REP, which can be affected by the PF rate. In the beginning of the rate development process, REP costs are projected using an estimate of the PF rate for the test period. These costs are included in the functionalized revenue requirements. If the ultimate PF rate differs from the estimated rate, the REP cost is recalculated. The PF rate is then recalculated based on the revised REP costs. This iterative process stops when the PF rate does not change from the previous iteration. This adjustment of the gross REP costs is necessary because the PF rate level can influence the level of the Residential Exchange costs included in the COSA. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 through 5.2.3.5 (COSA 06 FY 2002 through COSA 06 FY 2006).

5.2.4 Functionalization and Classification of Residential Exchange Program Costs

In the COSA, the gross REP cost is based on exchanging utilities' ASCs and the amount of their exchangeable loads. ASCs include the cost of power, transmission, and unbundled services associated with serving the exchanging utilities' exchangeable loads. The rate design adjustments follow the COSA in the WPRDS and use the results of the COSA performed on that portion of the revenue requirement classified to energy. Consequently, the REP cost that comes into the COSA with energy costs, demand costs, transmission costs, and unbundled services costs included, must be functionalized to generation and then classified to energy. In this way, REP costs are made to comport with all other Power function costs as they go through the rate design adjustment process. The functionalization and classification of REP costs are shown in Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.6 (COSA 07).

5.2.5 Classification

Classification in the WPRDS apportions generation costs between the demand, energy, and load variance components of electric power. This classification of the generation revenue requirement is shown in Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.7 (COSA 08).

The classification methodology BPA uses is based on the marginal costs of the components of power and generally accepted ratemaking procedures. BPA sets the price for demand using an adjusted marginal cost of demand. For this 2002-2006 Lookback, no change was made to the original adjusted marginal cost of demand. *See* Section 2.3.1.2 of the Final WPRDS Documentation, WP-02-FS-BPA-05A for a detailed description. In addition, BPA sets the price of the Load Variance Charge using its adjusted marginal costs. For this FY 2002-2006 Lookback analysis, no change was made to the original Load Variance Charge. *See* Final WPRDS Documentation, WP-02-FS-BPA-05A, Section 2.3.4.1, for a detailed description. Sales and revenues of these products are then forecast. Forecast revenues associated with demand are classified to demand. Forecast revenues for load variance are deemed to be equal to the cost of Load Variance and therefore classified as such. Generation costs classified to energy are the residual of total generation costs not classified to demand or load variance. By virtue of this classification scheme, costs of demand or load variance are not directly allocated to customer rate pools; rather, the costs are equal to the forecast revenues. Therefore, the only allocation of costs to customer rate pools in the COSA is for costs associated with energy.

5.2.6 Functionalized and Classified Revenue Credits

The revenue credits described below are functionalized to generation and classified to energy. Most of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by BPA's power rates.

5.2.6.1 U.S. Army Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) Project Revenues

COE and Reclamation Project revenues are payments from owners of downstream projects to the COE and Reclamation for benefits received (*i.e.,* additional generation) from the storage reservoirs owned by the COE and Reclamation. These revenues are not subject to revision through rates and hence are a revenue credit. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8 (COSA 09).

5.2.6.2 Section 4(h)(10)(C) Credits and Fish Cost Contingency Fund (FCCF)

Section 4(h)(10)(C) credits are provided by the Treasury to partially compensate BPA for the non-power portion of additional capital and operational costs that are incurred for fish migration. These credits are 27 percent of BPA's additional expenditures. This revenue was the estimate of what BPA would receive on average over a range of 50 different water conditions. The actual credit is determined after the year is completed. The operational costs vary with water conditions. The FCCF credit is similar to the section 4(h)(10)(C) credit since it is provided by the Treasury. The amount included here was the estimate based on the average of 50 water years. Only under the 15 worst water years would any credit be received, and then it would be much larger. The FCCF credit was limited by past expenditures BPA made for fish operations without receiving Treasury credits. The FCCF credit pool totaled about $325 million in the WP-02 Final Proposal. In extremely bad water years, this amount was accessed in order to avoid missing Treasury payments. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8 (COSA 09).

5.2.6.3 Colville Credit

The Colville credit is a credit BPA receives for being an agent of the U.S. Government and facilitating annual payments to the Colville Tribe as a result of a treaty settlement. The credit is equal to the amount BPA pays the Tribe, and it is essentially a predetermined amount. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8 (COSA 09).

5.2.6.4 Supplemental and Entitlement Capacity

BPA receives Supplemental and Entitlement Capacity revenues from private and public utilities as a result of contracts signed many years ago where the rates are fixed at a nominal amount per year. The revenue is a predetermined amount. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8 (COSA 09).

5.2.6.5 Irrigation Pumping Revenues

BPA receives a small amount of income from the delivery of pumping power at rates determined according to statutory requirements subject to the direction of the Secretary of the Interior and charged to Reclamation irrigation project customers. Although this revenue is not fixed, it totals less than $500,000 per year, depending upon the weather. This revenue is paid at the end of the year to the Treasury by Reclamation for BPA's credit. *See* Lookback WPRDS Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8 (COSA 09).

5.2.6.6 Energy Services Business Revenues

BPA received revenues associated with the activities of its Energy Services Business. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8 (COSA 09).

5.2.6.7 Property Transfers and Miscellaneous Revenues

Most of these estimated revenues were from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to change in the rate filing. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8 (COSA 09).

5.2.6.8 Power Services Transmission Costs, Revenues, and Credits

The Power Services (PS), in the course of marketing power, incurs transmission-related costs and generates transmission-related revenues and credits. The costs include, but are not limited to, those associated with providing ancillary and reserve services and General Transfer Agreements (GTAs). The revenues and credits are predominantly revenues associated with providing ancillary and reserve services. The net amount of these costs, revenues, and credits is classified to energy, and has the effect of reducing the FBS resource costs to be recovered by BPA's power rates. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.9 (COSA 10).

5.2.7 Allocation

Allocation is the apportionment of costs to customer classes. Allocation is performed by determining the relative sizes of resource pools and rate pools, pursuant to the rate directives contained in section 7 of the Northwest Power Act. Rate pools are groupings of customer classes (sales) for cost allocation purposes. BPA groups its sales into the "Priority Firm," "Industrial Firm," and "All Other" categories corresponding to sales under sections 7(b), 7(c), and 7(f) of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act as the FBS, Residential Exchange, and NR resource pools. Costs associated with each of these respective resource pools are grouped together to facilitate allocation to rate pools. The sizes of the rate and resource pools are determined from planning load and resource balances prepared in the Load Resource Study, Section 2 above.

The Northwest Power Act establishes three rate pools. The 7(b) rate pool includes public body, cooperative, and Federal agency sales as well as the sales to utilities participating in the REP established in section 5(c) of the Northwest Power Act. The 7(c) rate pool includes sales to BPA's DSI customers. The 7(f) rate pool includes all other long-term firm power BPA sells.

Subsequent to 1985, and implementation of the directives of section 7(c)(2) of the Northwest Power Act, BPA has had, for all practical purposes, only two rate pools: the 7(b) rate pool and all other loads.

For the FY 2002-2006 Lookback, the FBS resource pool consists of: (1) the FCRPS hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reductions in the capability of the above resources. Costs expected to be incurred during the rate period for replacement resources were included in the FBS resource pool. *See* Load Resource Study, Section 2 above. In addition to long-term resource acquisitions, short-term power purchases are made during the rate period. These short-term power purchases augment the Federal system to achieve load/resource balance on an annual basis as well as balance the Federal system to provide operational flexibility and provide for certain fish mitigation measures on a monthly and daily basis. The costs of such balancing purchases, as well as the cost of system augmentation to ensure load/resource balance, are considered to be FBS costs and are allocated as such.

5.2.7.1 Energy Cost Allocations

The process for allocating energy costs begins with an examination of critical period firm loads and resources to determine the amount of monthly firm energy surplus or deficit. A ratemaking load and resource balance for each month of the test period is then constructed from the Load Resource Study, Section 2 above, and other data. From this ratemaking load and resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate test period. Table EAF_05_01 shows the ratemaking energy loads and resources by pools. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.2.1 (EAF_05_01). Allocation factors, which apportion each resource pool's costs to BPA's classes of service, are calculated based on identified service from resource pools to rate pools in the ratemaking load and resource balances.

5.2.7.2 Energy Allocation Factors

When service from each resource pool to each class of service has been identified, the amount of such service is the allocation factor for the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown in the Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.2.2 (EAF_05_02). The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, REP, and NR allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Allocated energy costs are shown in the Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.10 (COSA 11) and Table 5.2.4.1 (RDS 01).

5.2.7.3 Other Cost Allocations

Costs not directly identifiable with rate pools, resource pools, or transmission costs allocated to the Power function are allocated as described below.

5.2.7.3.1 Conservation Costs

The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. The "legacy conservation" line item, as seen in the COSA 06 tables (*see* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 to 5.2.3.5), include: (1) debt service for BPA's previous resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; and (3) a share of the agency's total planned net revenues. The "conservation augmentation" line item, as seen in the COSA 06 tables (*see* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 to 5.2.3.5) includes costs associated with forecasted conservation for the FY 2002-2006 time period. In addition, the Northwest Power Act indicates that BPA should encourage the development of conservation and renewable resources in the region. Toward that end, the "energy efficiency" expenses line item, as seen in the COSA 06 tables (*see* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 to 5.2.3.5), reflects BPA's costs associated with providing conservation and renewable resources information in the region. In addition, these costs represent the technical support BPA provides in the region in the area of energy efficiency. The "energy efficiency" revenue line item seen in Table COSA 09 (*see* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.8) reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered.

5.2.7.3.2 BPA Program Costs

Some of BPA's program costs are not directly identified with any specific resource pool or customer class. An example is the cost of the ratemaking process. The generation portion of these costs is determined in the Revenue Requirement Study, WP-02-FS-BPA-02. The generation portion appears as BPA program costs. These costs, as seen in Table COSA 11 (*see* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.10), are allocated uniformly to all customer classes based on the total usage allocation factors for energy.

5.2.7.3.3 WNP-3 Settlement Exchange Agreement Costs

The revenue requirement includes costs related to the WNP-3 Settlement Exchange Agreement between BPA and four IOUs that have a 30 percent interest in the WNP-3 nuclear plant. Two types of WNP-3 Settlement Exchange costs are allocated in the COSA: plant-related costs and exchange energy costs. Under the WNP-3 Settlement Agreement, BPA is obligated to serve a specified amount of IOU load. Whether BPA must purchase to serve WNP-3 obligations is determined in RiskMod. To serve the IOU load, BPA may purchase either Company Exchange Energy from the IOUs or other, lower-cost power. The exchange energy costs are the projected costs of purchases of Company Exchange Energy (which may not exceed the costs of combustion turbines) or other purchases and storage in lieu of Company Exchange Energy. These costs are allocated uniformly to all loads using the total usage allocation factors for energy. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.1 (RDS 01).

5.2.7.3.4 Planned Net Revenues for Risk (PNRR)

PNRR is the amount of net revenues required to ensure that cash-flow from proposed rates fully meets BPA's probability standard for repaying Treasury on time and in full. The PNRR are functionalized entirely to generation and are allocated to resource pools that include Federal capital investments. The methodology is described and illustrated in the Revenue Requirement Study, WP-02-FS-BPA-02. For this FY 2002-2006 Lookback, the PNRR amount was not changed from the WP-02 Final Proposal.

The PNRR value found in the COSA 06 tables was the result of an iterative process between the RAM, the RiskMod, Non-Operating Risk Model (NORM), and the ToolKit models. The iteration was initiated with a seed value for PNRR in COSA 06 of the RAM. The resultant rates were used in RiskMod to produce probability distributions. These distributions were then used in the ToolKit to produce a new PNRR value and ending cash reserve amounts for new COSA 06 tables. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.3.1 to 5.2.3.5. For a further explanation of this iterative process, *see* Doubleday, *et al.*, WP-02-E-BPA-18. The PNRR value used in this FY 2002-2006 Lookback is the same as that used in the WP-02 Final Proposal.

5.2.8 COSA Results

The result of the COSA process is the allocation of the test period revenue requirements for energy to classes of service served with firm power. Tables COSA 11 and RDS 01 summarize the allocated generation energy revenue requirements and the total allocated revenue requirement recoverable from power rate classes of service, including transmission costs allocated to the Power function, that are recoverable from these classes of service. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.3.10 (COSA 11) and Table 5.2.4.1 (RDS 01).

5.2.9 Rate Design Step Adjustments

Rate design adjustments are performed sequentially in the order described below.

5.2.9.1 Excess Revenue Adjustment

The Excess Revenue Adjustment recognizes that revenues will be collected from certain classes of service to which costs are not allocated and credits these revenues to other customer classes. The source of excess revenues is projected secondary energy sales.

5.2.9.1.1 Secondary Energy Sales

On a planning basis and with system augmentation, BPA will have firm resources available to meet firm load obligations under 1937 water conditions. However, rates are set assuming that better-than-critical water conditions occur and, therefore, secondary energy sales and revenues are projected. These sales and revenues are projected on the 50-water-year run of the RiskMod model. *See* Conger, *et al.*, WP-02-E-BPA-15. The projected secondary energy revenue credits are allocated to firm loads so that BPA does not recover more than its revenue requirements. In previous rate cases, secondary energy revenue was referred to as “nonfirm” energy revenue. The secondary energy revenue value used in this FY 2002-2006 Lookback is the same as that used in the WP-02 Final Proposal.

The RiskMod model is used to project the level of secondary energy sales and revenues. BPA expected to sell secondary energy that will produce $2.578 billion in revenues over the five-year test period. After reducing these revenues by transmission charges totaling $348.7 million, BPA credited its firm power customers with excess revenues totaling $2.229 billion over the five-year test period. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.4 (RDS 11).

5.2.9.1.2 Allocation of Excess Revenues

Secondary energy revenues are used first to pay transmission costs associated with sales of secondary energy, with the remainder credited to firm power customers. These excess revenues are functionalized to generation and classified to energy. They are then allocated to loads served with Federal system resources (FBS and NR). The generation-related excess revenues are allocated in this manner because they are associated with secondary energy service and the cost of secondary energy is based on Federal resource costs only. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.5 (RDS 12).

The Nonfirm Energy (NF) Standard rate is based on the average cost of nonfirm energy. Table RDS 05 shows the calculation of the average cost of nonfirm energy. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.2 (RDS 05).

5.2.9.2 Firm Power Revenue Deficiencies Adjustment

BPA sold firm power at contractual rates and in the open market under the FPS-96 rate schedule. Sales of such firm power were not necessarily made at the fully allocated costs of the power. Therefore, either a revenue surplus or a revenue deficiency would result when a comparison is made between the costs allocated to the firm power and the revenues received from the sale of such power. BPA determined that in the FY 2002-2006 period it would receive $2.308 billion in revenues from the sale of firm power in various PNW and Southwest markets. Based on these sales estimates, transmission costs were estimated to be $260.4 million. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.4 (RDS 11). BPA allocated $3.459 billion in generation costs to the firm power sold. Therefore, there was a revenue deficiency of $1.411 billion over the five-year test period. This revenue deficiency of allocated costs in excess of revenues was charged to all firm power (PF, IP, NR) customers. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.4.6 and 5.2.4.7 (RDS 17 and RDS 18).

5.2.9.3 7(c)(2) Adjustment

DSI rates are based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that after July 1, 1985, the DSI rates will be set "at a level, which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to section 7(c)(2), the DSI rates are to be based on BPA's "applicable wholesale rates" to its preference customers and the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. To more accurately reflect the product BPA may purchase from the DSI customers, the name has been changed to Supplemental Contingency Reserve Adjustment (SCRA). However, for the WP-02 Final Proposal, BPA did not propose a uniform SCRA credit to be applied against DSI rates. Thus, the DSI rates were set equal to the applicable wholesale rate, plus a typical margin, subject to the DSI floor rate test and the outcome of the section 7(b)(2) rate test. *See* Section 5.2.9.5 below.

The applicable wholesale rate is the PF rate (in combination with the NR rate if new NLSLs were projected for the test period) at the DSI load factor. The typical margin is based on the overhead costs that preference customers add to BPA's price of power in setting their retail industrial rates. The typical margin value used in this FY 2002-2006 Lookback is the same as that used in the WP-02 Final Proposal.

The methods and calculations used to determine the typical margin are discussed in detail in Appendix A of the 2002 Final WPRDS. *See* WPRDS, Appendix A, WP-02-FS-BPA-05.

The net margin was 0.42 mills per kWh. As stated above, a zero SCRA credit was forecast in the WP-02 Final Proposal. This net margin was added to the seasonal and diurnal PF energy charges. These adjusted PF energy charges and the charge for demand were applied to the DSI test period billing determinants to determine the initial IP rate. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.9 (RDS 20).

The 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) delta, is allocated to non-DSI customers, primarily the PF customers. Because the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based, the entire process is repeated with the revised PF rate from the previous iteration until the size of the 7(c)(2) delta does not change when a successive iteration is performed. This process is accomplished through an algebraic solution that is shown in Table 5.2.4.10, RDS 21. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.10.

The size of the 7(c)(2) delta for the five-year test period was $874.7 million. This amount was allocated to PF and NR loads. The allocation was based on the energy allocation factors developed in the COSA. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.11 (RDS 22).

5.2.9.4 7(b)(2) Adjustment

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's public body, cooperative, and Federal agency customers' firm power rates applied to their requirements loads are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. If the 7(b)(2) rate test triggers, the public body, cooperative, and Federal agency customers are entitled to rate protection. The cost of this rate protection is borne by other purchasers of firm power. In order to make these cost adjustments, the PF rate is bifurcated. The two resulting rates are the PF Preference rate and PF Exchange Program rate.

The Section 7(b)(2) Rate Test Study, Section 6 below, indicates the 7(b)(2) rate test has triggered, and the PF rate applicable to BPA's preference customers must be adjusted down. The amount of protection needed is implemented through a reduction of the PF Preference rate in mills/kWh. BPA makes three adjustments in the rate design sequence to provide this protection to its preference customers and allocate the costs of the rate protection.

First, the PF Preference customer class is given a credit, which reduces its rate, by the amount of the protection indicated in the Section 7(b)(2) Rate Test Study, Section 6 below. The 3.6 mills/kWh protection amount results in a credit of $919.3 million to these customers. The cost of providing this protection is allocated to the remaining firm power customers in the rate design process (PF Exchange, IP, and NR). *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.15 (RDS 31).

The second adjustment is the 7(b)(2) Industrial Adjustment. The amount of this adjustment is the value of a recalculated 7(c)(2) delta at the lower PF Preference rate. The amount of the new 7(c)(2) delta is $179.7 million. This amount is allocated to the PF Exchange customer class and to the NR customer class. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.17 (RDS 34).

A third adjustment is necessary to allocate an increase in the gross Residential Exchange costs resulting from the bifurcation of the PF rate causing the PF Exchange Program rate to be higher than the average combined rate before the bifurcation. This results in higher Residential Exchange ASCs for deeming utilities. Therefore, the gross costs of the Residential Exchange must be recalculated. Any increase in such costs can only be allocated to the PF Exchange rate and the NR rate. The amount of the adjustment is $0 million and is determined through a set of iterations of the Residential Exchange cost model. The allocation of this amount is performed in the Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.19 (RDS 34A).

After the three 7(b)(2) adjustments are made (in the absence of a need for a DSI floor rate adjustment), BPA is then able to calculate Rate Design Step energy rates for the firm power classes of service. If the DSI rate falls below the floor rate, however, one final adjustment is necessary.

5.2.9.5 DSI Floor Rate Test

Section 7(c)(2) of the Northwest Power Act requires that the DSI rates in the post-1985 period "shall in no event be less than the rates in effect for the contract year ending June 30, 1985." Accordingly, a floor rate test is performed to determine if the IP rate has been set at a level below the floor rate. If so, an adjustment is made that raises the DSI rate to recover revenues at the

floor rate and credits other customers with the increased revenue from the DSIs. If the DSI rate has been set at a level above the floor rate, no floor rate adjustment is necessary.
The first step in calculating the floor rate is to apply the IP-83 Standard rate charges to test period (FY 2002-2006) DSI billing determinants. Although the energy billing determinants used for this calculation are identical to the energy billing determinants for the proposed rates, the demand billing determinants are different. The IP-83 Demand Charges are applied to billing determinants based on non-coincidental demand. The resulting revenue figure is then divided by total IP test period loads to arrive at an average rate in mills/kWh. This rate is reduced by an Exchange Cost Adjustment and a deferral that were included in the IP-83 rate. Both adjustments are made on a mills/kWh basis.

BPA has removed all transmission costs from the IP-83 rate to make a power-only floor rate comparison. The floor rate was adjusted for transmission costs by subtracting total transmission costs in mills/kWh from the original floor rate in the same manner that the Exchange Cost adjustment and deferral adjustments were completed. The mills/kWh amount was determined by dividing total transmission costs in the IP-83 rate by the total energy billing determinants for that rate period. The transmission cost adjustment amounted to 3.81 mills/kWh.

These calculations result in an undelivered DSI floor rate of 20.97 mills/kWh. The floor rate is then applied to the test period DSI billing determinants to determine floor rate revenues. Revenues at the proposed IP rate charges are compared to revenues at the floor rate. Because the proposed IP rate revenues are greater than the floor rate revenues, no adjustment is necessary to the Rate Design Step IP rate. Tables 5.2.4.12 and 5.2.4.13, RDS 23 and RDS 24, respectively, show the DSI floor rate calculation. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.2.4.12 and 5.2.4.13.

5.2.9.6 Rate Design Contra

The Rate Design Step adjustments move allocated costs between classes of service or adjust rates to account for excess revenues. Each rate design adjustment shows the classes of service to which the amount of the adjustment went. What is not shown for each rate design adjustment is the complementary accounting entry showing the source of the adjustment. The RAM keeps track of all such complementary accounting. When COSA allocated costs and rate design adjustments are summarized, it is necessary to further adjust the allocated costs by the amount of the complementary transactions. Such amounts are referred to as the rate design contra, which must be applied so that final allocated and adjusted costs to all rate classes will equal BPA's revenue requirements. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.22 (RDS 40).

5.2.9.7 Rate Design Results

Table RDS 41 summarizes the allocated costs and rate design adjustments for each class of service. Rate charges are calculated for each class by dividing the allocated and adjusted energy costs by the appropriate billing determinants. Summaries of the adjusted annual average energy rate charges are shown on Tables RDS 50, 51, and 52. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, 5.2.4.25 (RDS 50), 5.2.4.26 (RDS 51), and 5.2.4.27 (RDS 52). These annual average energy rates are shaped into monthly and diurnal periods based on the results of the WP-02 Marginal Cost Analysis Study, WP-02-FS-BPA-04.

5.2.10 Slice Cost Calculation

Because the purpose of the Lookback is to recalculate the PF Exchange rate and other rates necessary for the proper application of CRACs, and because the Slice rate was not subject to CRACs, the recalculation of the Slice rate was not necessary for the Lookback.

5.3 FY 2002-2006 Lookback Post-Processor Modeling

The FY 2002-2006 Lookback Post-Processor is a simplified model that determines the level of the PF Exchange rate for each year of the rate period and calculates what the IOUs' REP benefits would have been in the absence of the REP settlements.

The model uses the recalculated base PF Preference and PF Exchange rates from the FY 2002-2006 Lookback RAM2002 analysis. *See* Lookback Study Documentation, WP-07-FS-BPA-08, section 5.2. The model calculates a set of annual Cost Recovery Adjustment Clauses (CRACs) that adjust the PF Preference and PF Exchange rates so that they will recover the proper revenues for the rate period.

To determine the revenues to be recovered from the CRACed rates, the actual revenues recovered from actual rates in effect during the rate period are determined. The actual revenues collected for the rate period are then adjusted by: (1) subtracting the amount of REP Settlement Agreement Benefits paid as expressed in Section 13; (2) subtracting the net cost to BPA of furnishing power to IOUs, included in Section 13; and (3) adding the net REP benefits determined by using the recalculated base PF Exchange rate and the backcast utility ASCs and eligible exchangeable loads, as expressed in Section 14. These annual adjusted revenue amounts for each fiscal year are the "Annual Revenue Targets."

For the Lookback analysis, it is assumed that all other revenues and credits except those provided by firm sales under PF rates remain the same in a world with or without the REP settlements. Therefore, only PF rate revenues are used in the model to determine the Annual Revenue Targets.

If the model projects that revenues from recalculated rates fall short of the Annual Revenue Targets for a year, then the base PF Preference and PF Exchange rates are increased by means of a CRAC percentage increase to both rates. The CRAC increases the revenue and, in turn, decreases the level of net REP benefits until the difference between the net revenues collected and the Annual Revenue Target is zero. The inverse is true if revenues over-collect the Annual Revenue Target. The calculated IOU REP FY 2002-2006 benefits at the CRACed PF Exchange rates are then reported out to be used in the Lookback Amount calculations. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, and 5.3.6.

5.4 Rate Analysis Results

The FY 2002-2006 Lookback base rates from the WP-02 RAM2002 are: a PF Preference rate of 25.33 mills/kWh and a PF Exchange rate of 39.24 mills/kWh. The average CRACed PF Preference is 27.59 mills/kWh, and the average CRACed PF Exchange rate is 42.46 mills/kWh. The Lookback recalculated IOU REP benefits for FY 2002-2006 average about $134.9 million per year. *See* Table 14.1, Lookback REP Benefits-FY 2002-2006, in this Study and Study Documentation, WP-07-FS-BPA-08A, Table 5.2.4.20 (PF 2007-09), Table 5.2.4.21 (PFx 2007-09), and Table 5.3.6 (Post-Processor 6).

6. SECTION 7(b)(2) RATE TEST STUDY, FY 2002-2006

6.1 Introduction

This section addresses the section 7(b)(2) rate test for FY 2002-2006 Lookback analysis. Recalculations of the section 7(b)(2) rate tests are necessary to determine a base PF Exchange rate to be used in the Lookback analysis. There are two phases of the 7(b)(2) rate test for the Lookback analysis, the FY 2002-2006 rate test and FY 2007-2009 rate test. The first rate test was conducted using data available from both the WP-02 Final Proposal and the WP-02 Supplemental Proposal in and around the spring of 2001. In addition, assumption changes have been made to reflect the changed conditions due to removal of the REP settlements. The second rate test was conducted using the data available from the WP-07 Final Proposal, and is discussed in Section 10 of this Study.

Section 7(b)(2) of the Northwest Power Act, 16 U.S.C. § 839e(b)(2), directs the BPA to conduct a comparison of the projected rates to be charged its preference and Federal agency customers for their firm power requirements, over the rate test period plus the ensuing four years, with the costs of power (hereafter called rates) to those customers for the same time period if certain assumptions are made. The effect of this rate test is to protect BPA's PF preference customers' wholesale firm power rates from certain specified excess costs resulting from provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of PF preference customers to other BPA loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirements loads of BPA's public body, cooperative, and Federal agency customers (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 (Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (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. Next, each of the nominal rates for the two cases is discounted to the beginning of the rate period. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average Program Case rate is greater than the average 7(b)(2) Case rate, the rate test triggers. The difference between the average Program Case rate and the average 7(b)(2) Case rate determines the amount to be reallocated from the 7(b)(2) Customers to other firm loads.

6.1.1 Purpose and Organization of Study

The purpose of this study is to describe the application and results of the Section 7(b)(2) Rate Test Methodology for the FY 2002-2006 Lookback analysis. If the 7(b)(2) rate test triggers, as it has in the FY 2002-2006 Lookback analysis, the cost adjustment amount that is to be incorporated into the rate design process is calculated. The accompanying Documentation for Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-08A, Section 6, contains the documentation of the Excel models and data used to perform the 7(b)(2) rate test.

This section is organized into two major subsections. The first 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 and the results of the rate test for the FY 2002-2006 Lookback analysis. The second section presents a set of tables showing the calculations performed for the rate test and the results of the test. The financing benefits analysis has not been changed from that used in the WP-02 Final Proposal and is not included in this study. *See* Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A, Appendix A.

6.1.2 Basis of Study

6.1.2.1 Legal Interpretation

Prior to the first phase of its 1985 general rate proceeding, BPA published the Legal Interpretation of section 7(b)(2) of the Northwest Power Act (1984 Legal Interpretation), 49FR23,998 (1984). The 1984 Legal Interpretation is hereby incorporated by reference. Major provisions of the 1984 Legal Interpretation are listed below. It should be noted that BPA revised the 1984 Legal Interpretation as part of the WP-07 Supplemental Proceeding. However, except for the treatment of Mid-Columbia resources, this FY 2002-2006 Lookback analysis was conducted under the 1984 Legal Interpretation.

6.1.2.1.1 Legal Interpretation: Five Assumptions

The 7(b)(2) Case is modeled by limiting the differences between the two cases to only the five assumptions specified in section 7(b)(2) and the unavoidable natural consequences of those assumptions on the ratemaking processes; all others assumptions remain the same between the Program Case and the 7(b)(2) Case.

6.1.2.1.2 Legal Interpretation: 7(a) Limitation

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 Act.

6.1.2.1.3 Legal Interpretation: Applicable 7(g) Costs

Applicable 7(g) costs are subtracted from the Program Case rates before those rates are compared with the rates in the 7(b)(2) Case. The treatment of applicable 7(g) costs in this rate test is the same as it was for the WP-02 Final Proposal.

6.1.2.1.4 Legal Interpretation: DSI Service

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

6.1.2.1.5 Legal Interpretation: DSI Served as Firm

The DSI loads assumed to be served by the 7(b)(2) Customers are assumed to be served wholly with firm power purchased from BPA.

6.1.2.1.6 Legal Interpretation: Within or Adjacent

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.

6.1.2.1.7 Legal Interpretation: Federal Base System

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 as the pre-Northwest Power Act BPA power sales contracts with the DSIs expire.

6.1.2.1.8 Legal Interpretation: 7(b)(2)(D) Resource Stack

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 the 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. Please note that the proposed Legal Interpretation would exclude the Mid-Columbia resources sold to the regional investor-owned utilities from the 7(b)(2) Case resource stack.

6.1.2.2 Implementation Methodology

A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on rate test implementation methodology issues. The issues addressed in the hearing are discussed in the Administrator's Record of Decision (ROD) for Section 7(b)(2) Implementation Methodology (7(b)(2) ROD), b-2-84-F-02, published in August 1984. The 1984 Implementation Methodology and ROD are hereby incorporated by reference. In this WP-07 Supplemental Proposal, BPA is proposing a revised Section 7(b)(2) Implementation Methodology. However, except for the treatment of Mid-Columbia resources, this FY 2002-2006 Lookback analysis is being conducted under the 1984 Implementation Methodology. The major issues resolved in the 1984 Implementation Methodology are discussed below.

6.1.2.2.1 Implementation Methodology: Reserve Benefits

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 that "within or adjacent" DSI loads are less than the total amount of DSI loads served by BPA. *See* Documentation for Wholesale Power Rate Development Study, WP-02-FS-BPA-05, Appendix B. In the WP-02 Final Proposal, reserves provided under the Northwest Power Act were forecast to be zero. This assumption eliminated the need for a financing benefits analysis to quantify the value of reserves for the rate test.

Financing benefits in the 7(b)(2) Case are quantified for planned or existing resources that have been acquired by BPA or are planned to be acquired in the Program Case during the 7(b)(2) rate test period. The financing benefits analysis used in this FY 2002-2006 Lookback rate test is unchanged from that used in the WP-02 Final Proposal. The financing benefits in the 7(b)(2) Case were estimated by a financial consultant, Sutro & Co. Incorporated, which estimated the resource sponsor's financial cost for the 7(b)(2)(D) resources assuming that BPA did not acquire the resource output. The changed financing benefits from the Program Case assumptions for those resources required to meet the 7(b)(2) Customers' loads may increase the costs of those resources in the 7(b)(2) Case. *See* Section 7(b)(2) Rate Test Study Documentation, WP-02-FS-BPA-06A.

6.1.2.2.2 Implementation Methodology: Natural Consequences

Natural consequences result from reflecting the five assumptions in the 7(b)(2) Case rates while keeping all the underlying ratemaking premises and processes the same for both cases. Three natural consequences were identified for possible modeling in the rate test: elasticity of demand, the level of surplus firm power available, and the size of nonfirm energy markets.

6.1.2.2.3 Implementation Methodology: Rate Modeling

The 7(b)(2) rate test in the FY 2002-2006 Lookback was conducted using three large spreadsheet models. The first of the spreadsheet models is the Program Case RAM (RAM-Prog), used to calculate Program Case rates. RAM-Prog is the same model used to calculate the WP-02 Final Proposal rates. The second model is a 7(b)(2) Case version of the RAM (RAM-7b2). RAM-7b2 model differs from RAM-Prog by only the five assumptions specified in section 7(b)(2) and the natural consequences of those assumptions on the results of ratemaking processes. The third model is the Residential Exchange Model of the RAM (ResExRAM), which calculates the costs of the REP and electronically transfers that information to RAM-Prog. The output of these spreadsheet models is in the Lookback Study Documentation, WP-07-FS-BPA-08A, Section 6.

6.1.2.2.4 Implementation Methodology: Rate Discounting

The projected rate for each year of the section 7(b)(2) rate test period is discounted back to the beginning of the rate proposal test period, using a factor based on BPA's projected borrowing rate for each of the rate test years. The discounted rates are then averaged for each case and the result rounded to the nearest tenth 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-tenth of a mill or more. If the rate test triggers, the difference between the two rates is multiplied by the billing determinants of the PF Preference customers for the rate period to determine the amount of costs to be reallocated from the PF Preference customers to other BPA firm loads in the rate period.

6.2 Methodology

Implementing section 7(b)(2) consists of incorporating the determinations from the 1984 Legal Interpretation and the 1984 Implementation Methodology ROD into the RAM-Prog and RAM-7B2 models.

6.2.1 Sequence of Steps

The RAM-Prog and RAM-7B2 models simulate BPA's ratemaking process by performing the steps needed to develop wholesale power rates. Each step is described as it is performed to calculate rates for the Program Case and the 7(b)(2) Case.

6.2.1.1 Program Case RAM

This model calculates annual Program Case rates for FY 2002-2006 and the following four years, FY 2007-2010. Except for the treatment of Mid-Columbia and conservation resources, the ratemaking methodology used to calculate rates for the Program Case of the 7(b)(2) test are identical to those used in calculating average rates for the WP-02 Final Proposal. However, as discussed below, the data used in this FY 2002-2006 Lookback analysis is in some cases substantially different than the data used in the WP-02 Final Proposal.

6.2.1.1.1 Sales

For this FY 2002-2006 Lookback analysis, the sales forecast used to develop rates for the Program Case covers the period FY 2002-2010, and is the same forecast used to develop BPA's FY 2002-2006 Lookback base rates described in Section 5.2. Sales forecasts are as explained Section 2. Exchange loads are explained in Section 7. For this FY 2002-2006 Lookback analysis, BPA is recognizing the DSI load reduction agreements (DSI LRAs) that were signed before June 20, 2001. Therefore, the DSI loads are reduced from the original 1,440 aMW for each year of the test period to 637 aMW (FY2002), 884 aMW (FY2003), 1,389 aMW (FY2004), 1,389 aMW (FY2005), 1,396 aMW (FY2006), and 1,440 aMW (FY2007-10). *See* WP-07-FS-BPA-08A, Section 6, Table 6.1.1.3. The reduction in DSI load due to the DSI LRAs results in BPA being over augmented with power beyond that needed to serve firm loads in FY 2002 and FY 2003. The over augmented power due to the recognition of the DSI LRAs is assumed to be sold in the region at a price that is two times the cost of the DSI LRAs, plus the lost IP revenue.

BPA's total sales obligations are comprised of COUs, IOUs, DSIs, Federal agencies, Residential Exchange load, and contractual sales. All forecasted sales are entered into the RAM models with diurnally and seasonally differentiated energy and seasonally differentiated demand billing determinants.

6.2.1.1.2 Load/Resource Balance

The RAM models for the Program Case do not normally perform load/resource balance calculations. Rather, under normal conditions, the models depend on the load/resource balance performed in the Loads and Resources Study, Section 2. Data from the Loads and Resources Study are used to ensure that resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves PF loads (Federal agency, COU, and Residential Exchange loads) until FBS resources are exhausted. Residential Exchange resources then are used to serve any remaining PF load. DSI, New Resource, and Surplus Firm Power loads are combined into a single rate pool. Remaining Residential Exchange resources and new resources are used to serve this combined rate pool. However, as stated above, the recognition of the DSI LRAs has required a change in the assumed DSI load, and that change required changes in the assumed additional system augmentation beyond the amount that had been pre-purchased as of June 2001, and the amount of secondary sales. For modeling purposes, the cost of the DSI LRAs as well as the additional secondary sales revenue are both credited to the system augmentation costs and the resultant value for each year can be seen in the COSA 06 tables for FY 2002 to FY 2006. See WP-07-FS-BPA-08A, Section 6, Table 6.1.3.1 to Table 6.1.3.5.

6.2.1.1.3 Revenue Requirement

The revenue requirement for this FY 2002-2006 Lookback analysis is explained in Section 3. The majority of the change is associated with greater COU loads, greater system augmentation costs and greater gross costs of the REP. FBS costs are based on the interest and amortization of the Federal debt for the hydro projects; planned net revenues; hydro operation and maintenance costs; costs related to WNP-1, -2, and -3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Hanford and Trojan nuclear plants; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. Residential Exchange resource costs are based on the ASCs of utilities participating in the REP. New resource costs are those of the Idaho Falls contract, the generation portion of competitive acquisitions, geothermal, the Cowlitz Falls Project, and other firm purchased power. Other BPA costs include BPA’s administrative and general costs, the costs associated with the WNP-3 Settlement Agreement, and the costs associated with BPA legacy conservation and energy efficiency programs.

6.2.1.1.4 Cost Allocation

Allocation of projected costs to customer classes is performed on an average energy basis in the RAM-PROG and RAM-7B2 models. Generation costs are allocated by the use of Energy Allocation Factors calculated using the results of the Loads and Resources Study. Conservation and billing credit costs, BPA administrative and general expenses, energy service business revenues, and WNP-3 Settlement Agreement costs are allocated across all BPA firm loads. The cost allocation procedures for the Program Case are the same as those for the WP-02 Final Proposal.

6.2.1.1.5 Rate Design

The adjustments made to allocated costs in the RAM-PROG for the Program Case are the same as those made in the WP-02 Final Proposal. These adjustments include excess revenue credits; the surplus firm power revenue surplus/deficiency; the section 7(c)(2) delta and margin; the DSI floor rate adjustment; and the exchange cost adjustment.

Excess Revenues are earned from the sale of secondary energy that is assumed available from the average of 50 water years for secondary energy generation. Excess revenues are credited to loads served by FBS and new resources. The RAM-PROG and RAM-7B2 models use the secondary energy sales revenue forecast produced by the RiskMod model, documented in the Final Risk Analysis Study, WP-02-FS-BPA-03. For this FY 2002-2006 Lookback analysis, no changes are made to the original levels of secondary energy sales from the WP-02 Final Proposal.

The Surplus Firm Power Revenue Surplus/Deficiency results when the available surplus firm power is sold at other than its fully allocated cost. In addition, BPA assumes that long-term extra-regional contracts will continue in the power sales mode, at amounts and rates set by the individual contracts. For this FY 2002-2006 Lookback analysis, no changes are made to the

WP-02 Final Proposal levels of surplus firm power sales. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that power after transmission costs are deducted, equals the surplus firm power revenue surplus/deficiency. The surplus/deficiency is allocated to firm loads served by FBS and new resources. The revenues from capacity sales are also treated like the surplus firm power revenue surplus/deficiency and are allocated to all firm loads served by FBS and new resources.

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. The net margin is 0.46 mills/kWh in nominal dollars. The DSI rate equals the applicable wholesale rate to PF Preference customers plus the net margin.

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

The Residential Exchange Cost Adjustment alters BPA's revenue requirement because changes in the PF rate result in changes in the cost of the REP. RAM-Prog iterates with the ResExRAM to converge on the cost of the REP that is associated with the calculated PF rate. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Section 6, Table COSA 06.

Rate Mitigation, Low Density Discount costs, and Conservation and Renewables Discount (C&R Discount) costs are included in the rate calculations for the PF rate class. For this Lookback analysis, no changes are made to the WP-02 Final Proposal levels of Low Density Discount costs and C&R Discount costs. For a further discussion of these items, *see* Sections 2.8, 2.9, and 2.10 in the Final WPRDS, WP-02-FS-BPA-05.

6.2.1.2 7(b)(2) Case

The 7(b)(2) Case is modeled in the same way as the Program Case except where section 7(b)(2) of the Northwest Power Act requires specific assumptions to be made that modify the Program Case.

6.2.1.2.1 Sales

The sales forecasts input to RAM-7B2 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) Customer sales are adjusted to exclude estimates of programmatic conservation savings, competitive acquisitions conservation and billing credits. 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 preference customers for the entire rate test period as 100 percent firm loads. Sales to DSIs not "within or adjacent" are assumed to be served by IOUs.

6.2.1.2.2 Resources

The size of the FBS is identical for the two cases; the Program Case and the 7(b)(2) Case. If the FBS is insufficient to serve all 7(b)(2) Customer loads in the 7(b)(2) Case, additional resources are assumed to come on-line. Consistent with the 1984 Implementation Methodology, three types of additional resources can be added to serve loads. As discussed in Doubleday, *et al.*, WP-07-E-BPA-60, the portions of the Mid-Columbia Hydro resources that are contracted to regional IOUs were not considered to be non-dedicated for purposes of the 7(b)(2) rate test. Therefore, these resources were removed from the 7(b)(2)(D) resource stack. In addition, BPA has removed obsolete programmatic conservation resources from the 7(B)(2)(D) resource stack. Sufficient 7(B)(2)(D) stack resources were available to meet 7(b)(2) Case loads through the rate test period. The cost of resources brought on-line in the 7(b)(2) Case is affected by the 7(b)(2) financing benefits analysis.

6.2.1.2.3 Financing Benefits

The financing benefits analysis required by section 7(b)(2)(E)(i) of the Northwest Power Act was performed by BPA's financial advisor, Sutro & Co. Incorporated. As stated above, the financing analysis has not been changed from that used in the WP-02 Final Proposal. *See* WP-02-FS-BPA-06A. The financial advisor's analysis appears as Appendix A to that document. It shows that the estimated financing benefit of BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by public utilities is 14 basis points lower than the 7(b)(2) Case without BPA backing. This increases the financing costs for additional resources in the 7(b)(2) Case, thereby increasing the 7(b)(2) Case power cost for the 7(b)(2) Customers. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 24 basis points between an assumed revenue bond issued with and without a BPA contract for the project. BPA-sponsored programmatic conservation is 4 basis points lower than the same activities under the 7(b)(2) Case without BPA backing. The debt associated with the Idaho Falls Project was refunded to take advantage of lower interest rates. However, since the owner of the project, the City of Idaho Falls, can withdraw from the contract with BPA at its option, the new interest rate is not affected by Idaho Falls' contractual relationship with BPA. Therefore, no financing differential is associated with Idaho Falls.

6.2.1.2.4 Load/Resource Balance

For this FY 2002-2006 Lookback analysis, the size of the FBS and the amounts of balancing purchase power and augmentation power are the same in the 7(b)(2) Case as in the Program

Case. In addition, the Program Case assumes a small amount of new resource power that is not assumed in the 7(b)(2) Case. The Program Case is in load/resource balance during the rate period. The 7(b)(2) Case sales assume no conservation savings and are therefore greater than the Program Case sales. The FBS was sufficient to meet the 7(b)(2) customer loads as well as the FPS Pre-Subscription contract loads during the FY 2002 to FY 2007 time period. The FBS was insufficient to meet the 7(b)(2) Customer loads and BPA's Hungry Horse obligations during the FY 2008-2010 rate test period out-years; therefore, additional resources were needed. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Table 6.2.2.1. These additional resources were taken from the 7(b)(2)(D) resource stack in the order of least cost first, and their cost is added to the 7(b)(2) Case revenue requirement. The addition of these resources provides more power capability than is necessary to achieve load/resource balance, thus increasing the availability of surplus firm power in the 7(b)(2) Case. Therefore, additional surplus power sales revenues were forecast in the 7(b)(2) Case. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Section 6, Table 7b2Resource_01.

6.2.1.2.5 Revenue Requirement

The revenue requirement in the 7(b)(2) Case is comprised of the same costs and budget information as in the Program Case, with some modifications. The 7(b)(2) Case excludes Program Case revenue requirement amounts budgeted for conservation, direct generation acquisitions of new resources, and REP costs. Repayment studies are then performed for each year of the 7(b)(2) rate test period, using the same methodology as for the Program Case.

6.2.1.2.6 Cost Allocation

Section 7(b)(2) Customers are allocated costs of the FBS and new resource costs according to their use of the respective resources. Purchasers of surplus firm power are allocated FBS costs and new resource costs according to their use of the resources.

6.2.1.2.7 Rate Design

In the WP-02 Final Proposal, BPA estimated reserve benefits provided by the DSIs to be zero. *See* Section 6.2.2.1 above and the Final WPRDS, WP-02-FS-BPA-05, Appendix B. However, an estimate of possible stability reserves provided by the DSIs to the Transmission was included. *See* Lookback Study Documentation, WP-07-FS-BPA-08A, Section 6, Table 6.2.5.2, RDS 11. Other rate design adjustments in the 7(b)(2) Case are performed in the same manner as in the Program Case.

6.3 Summary of Results

Results for the two cases are summarized in Tables 6.1 and 6.2 below.

6.3.1 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 WP-02 Final Proposal. Table 6.1 below shows the projection of undiscounted nominal Program Case rates.

6.3.2 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) 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 6.2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

6.3.3 The Rate Test

The RAM-PROG model performs the section 7(b)(2) rate test after it and the RAM-7b2 model calculate the two sets of rates. First, the projected Program Case rates are reduced by the applicable 7(g) costs 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 7(g) costs quantified for the WP-02 Final Proposal rate test are comprised of BPA-acquired and projected conservation and billing credits, energy efficiency costs, and C&R Discount costs. The projected rates for each year are then discounted to FY 2002 using factors based on BPA's projected borrowing rate for each year. Table 6.3 below shows BPA's future borrowing rates that were used in the discounting procedure and the corresponding cumulative discount factors. The discounted rates for each case then are averaged over the test period, rounded to one decimal place, and compared (*see* Table 6.4 below). As shown in Table 6.4 below, the rate test triggers. Therefore, a rate adjustment is required. *See* Chapter 5.

TABLE 6.1
PROGRAM CASE RATES

(nominal mills/kWh)

Fiscal Year	Rate	Applicable 7(g) Costs	Net Rate
2002	29.829	2.011	27.818
2003	30.850	2.001	28.849
2004	32.531	1.937	30.594
2005	32.697	2.090	30.608
2006	32.851	2.292	30.559
2007	34.036	2.188	31.848
2008	33.873	2.311	31.562
2009	34.672	2.521	32.151
2010	34.346	2.813	31.533

TABLE 6.2
7(b)(2) CASE RATES

(Nominal mills/kWh)

Fiscal Year	7(b)(2) Rate
2002	20.142
2003	22.374
2004	24.791
2005	24.945
2006	25.056
2007	27.833
2008	28.711
2009	30.978
2010	29.656

TABLE 6.3
DISCOUNT FACTORS FOR THE RATE TEST

Fiscal Year	Annual BPA Borrowing Rate	Cumulative Discount Factor
2002	.0708	.9339
2003	.0689	.8737
2004	.0690	.8173
2005	.0688	.7647
2006	.0685	.7157
2007	.0681	.6700
2008	.0677	.6275
2009	.0672	.5880
2010	.0667	.5513

TABLE 6.4
COMPARISON OF RATES FOR TEST

(Discounted mills/kWh)

Fiscal Year	Discounted Program Case Rate	Discounted 7(b)(2) Case Rate
2002	25.979	18.811
2003	25.205	19.548
2004	25.004	20.262
2005	23.405	19.075
2006	21.870	17.932
2007	21.339	18.649
2008	19.806	18.017
2009	18.906	18.216
2010	17.383	16.348
Average Rate	22.1	18.5
Difference of Average Rates	3.6	

7. BACKCAST OF IOU ASCS, FY 2002-2006

7.1 2002 -2006 Backcast Overview

The purpose of this section is to estimate the annual Average System Cost (ASC) determinations that would have been made had the investor-owned utilities (IOUs) submitted ASC filings with BPA for 2002-2006.

During FY 2002-2006, no ASC filings were made with BPA. Such filings would have been made had BPA and the IOUs not executed Residential Exchange Program (REP) Settlement Agreements and instead had an active REP. Consequently, annual ASCs must be estimated in order to determine what REP payments the IOUs would have received for this period under an active REP. This section of the Lookback Study describes how these ASC determinations were made and presents the results. Annual ASCs were calculated for Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy. Public utilities were not included in this analysis.

To estimate these ASCs, a detailed review of financial and operating data was completed for each IOU for 2002-2006. The results of this review established annual "backcast" ASC determinations for each utility. This section focuses on the backcast determinations for FY 2002-2006 only. See Section 11 of this Study for backcast determinations for FY 2007-2008.

7.2 Backcast ASC Determination Process

"Backcast" is BPA's term for ASCs that BPA would have determined had the REP been operational during the WP-02 rate period. A backcast ASC is based primarily on review and analysis of 2002-2006 FERC Form 1 data and other data sources as required. These data were entered into the 1984 ASC Cookbook model to establish estimates of the ASCs for each of the IOUs for the WP-02 rate period.

During the data collection and model input process, it was recognized that the existing ASC Cookbook model, based on the 1984 ASC Methodology (ASCM), was outdated. Since the 1984 ASCM was approved, numerous changes were made to the FERC Uniform System of Accounts that required changes to the ASC Cookbook model. For example, FERC added accounts for derivatives, regulatory assets and liabilities, and transmission of power for others. If BPA had an active REP program, changes to the FERC Uniform System of Accounts would have been incorporated into the 1984 ASCM. Also, it was found that when data were manually transferred from a specific utility's records to the ASC Cookbook model, input errors resulted in some instances. The ASC Cookbook was updated to reflect changes to the FERC Uniform System of Accounts and new and corrected information.

BPA complied with the 1984 ASCM when it prepared the backcast ASCs, with one exception: use of FERC Form 1 data as the primary source of data instead of jurisdictional rate orders from state regulatory commissions. Other than use of FERC Form 1 data, BPA complied with the 1984 ASCM for inclusion and functionalization of costs in the ASC Cookbook model. Use of FERC Form 1 data as the primary source of data for the ASC Cookbook model for the backcast resulted in a consistent and uniform development of the ASCs for the IOUs. The FERC Form 1 data populated the ASC Cookbook, an Excel-based computer modeling tool. Once populated with a utility's financial and operating data, the ASC Cookbook separated, or "functionalized," the total costs and revenues into production, transmission, and distribution functions; *i.e.*, to functions that may be exchanged (exchangeable costs) and to those that may not be exchanged.

The sum of all exchangeable costs is Contract System Cost (CSC). Contract System Load (CSL) is the sum of total retail load and distribution losses. ASC is calculated by dividing a utility's

CSC by its CSL. The resulting backcast ASC for each IOU is one factor used to determine estimates of REP benefits. The REP benefit determinations are discussed in Section 14 of this Lookback Study.

7.3 Data Input For ASCs

BPA developed backcast ASCs for each year and each IOU to estimate the costs each utility would have filed pursuant to the 1984 ASC Methodology and their RPSAs.

To determine costs, revenues, and loads, annual historical data was used that was reported by each IOU through FERC Form 1 filings. When appropriate, a utility's Result of Operations report was also used. FERC Form 1 data for each IOU were downloaded and linked directly to the ASC Cookbook models. This process allowed for accurate, straightforward, and efficient data entry to complete the estimates.

7.4 Backcast ASC Calculation

A backcast ASC calculation is a four-step process to determine the following:

(1) exchangeable rate base;
(2) return on rate base;
(3) operating expense; and
(4) calculation of ASC.

7.4.1 Exchangeable Rate Base Calculation

Exchangeable rate base is determined by identifying net production and transmission assets and liabilities that are functionalized to production and transmission. These assets and liabilities include total plant investments less depreciation and amortization reserves. The 1984 ASC

Methodology specifies which assets and liabilities are to be functionalized to production and transmission.

7.4.2 Return on Rate Base Calculation

Return on rate base is calculated by multiplying exchangeable rate base by a cost of capital percentage. The 1984 ASCM established that the cost of capital is equal to the weighted cost of debt. The weighted cost of debt was derived by dividing total interest expense by total outstanding debt. Both values are found in the FERC Form 1. Return on rate base is a direct cost that is included in the Contract System Cost.

7.4.3 Operating Expense Calculation

Operating Expense is determined by accumulating total operating expenses for a utility. Operating Expense includes operation, maintenance, and fuel costs associated with generating resources and transmission plant, purchased power and other power supply expenses, transmission expenses, administration and general expenses, depreciation and amortization, and exchangeable taxes. Operating Expense is reduced by production-related credits that include the net disposition of utility plant, revenue from sales for resale, and other miscellaneous revenue credits.

7.4.4 Determination of NLSL and Associated Resource Costs

NLSL load and resource costs used to serve NLSLs are contained in the NLSL Model, which shows any NLSL(s) at each utility and any reduction to Contract System Cost associated with serving an NLSL(s). The NLSL deductions are made in the Contract System Cost and Contract System Load calculations. See the NLSL Analysis and background letter located at the end of the Supplemental Final Lookback Documentation, WP-07-FS-BPA-08B.

7.4.5 Contract System Cost Calculation

Contract System Cost is determined as follows:

Contract System Cost = (operating costs) – (wholesale market revenues and other revenue credits) + (return on rate base) – (cost of serving NLSLs)

7.4.6 Contract System Load

Prior to completing the final step in an ASC rate calculation, it is necessary to determine the Contract System Load of a utility. Contract System Load is the sum of total consumer end-use load of a utility that is reported in the FERC Form 1, plus a 5 percent distribution loss factor, less any NLSL.

7.4.7 Backcast ASC Calculation

The base ASC determination is calculated by dividing a utility's Contract System Cost by the utility's Contract System Load.

7.5 Changes Made to the ASC Cookbook Model

It was recognized that the existing ASC Cookbook model, based on the 1984 ASC Methodology (ASCM), was outdated. Had the REP been in place during FY 2002-2006, updates to the ASCM reflecting changes in the FERC Uniform System of Accounts would have been completed, and any errors would have been corrected in the process of making ASC determinations. For this backcast exercise, the ASC Cookbook was updated and corrected to reflect changed circumstances and information.

The following sections outline both major and minor revisions that were made in the 1984 ASC Cookbook model. The revisions include changes in assumptions, addition of new accounts, deletion of outdated accounts, deletion of repetitive line items, and updates/changes to functionalization codes.

For details of specific line items, refer to the 1984 ASC Cookbook template published in the WP-07 Final Proposal, WP-07-FS-BPA-05B, and the revised 1984 ASC Cookbook. *See* Lookback Study WPRDS Documentation, WP-07-FS-BPA-08A, section 7.

7.5.1 Sales for Resale

Sales for Resale revenues are functionalized to production. It is assumed that a utility's resources are used first to meet its requirements load and then to support its wholesale marketing activities. In the ASC forecast, the Sales for Resale credit consists of Long-term firm sales, Intermediate-term firm sales, and Short-term Sales for Resale as reported in a utility's FERC Form 1. In the ASC Forecast contained in Section 5.1 of this document, the Sales for Resale credit is 80 percent of the actual reported amount. For development of the backcast ASCs, 100 percent of the Sales for Resale credit was used in determining the ASCs of the IOUs. This change reflects actual ratemaking practice for the IOUs.

7.5.2 Other Revenue Accounts, FERC Account Numbers 450-456.1

The "Other Revenue Accounts" are accounts established to record revenues that are not directly tied to the sale of power. The accounts include: Sale of Water/Water Power, Rent from Utility Property, Wheeling Revenue, and Other Miscellaneous Revenues. Listed below are the changes to Accounts 450-456.1.

7.5.2.1 Functionalization of Account 453, "Sale of Water/Water Power"

BPA changed the functionalization of Account 453, "Sale of Water/Water Power" from Direct Production to Direct Distribution. Account 453 includes revenues derived from the sale of water for irrigation, domestic and industrial purposes. Though the revenues might be associated with a hydro facility, the revenues are not directly tied to the generation of power.

7.5.2.2 Functionalization of Account 454, "Rent from Property"

BPA changed the functionalization of Account 454, "Rent from Property," from Direct Production to the Transmission and Distribution (TD) ratio. Account 454 includes revenue from the rental of utility property such as buildings and other assets. However, in the description of this account there are no revenues that are tied directly to generation facilities. The TD ratio is used to account for the rental of buildings and property as well as the revenues derived from telecommunication and fiber systems that are attached to the distribution and transmission poles and towers.

7.5.2.3 Functionalization of Account 456, "Other Revenues"

BPA changed the functionalization of account 456, "Other Revenues," from Direct Transmission to production/transmission/distribution/general (PTDG) ratio. FERC established Account 456.1 to account for wheeling revenues; therefore, the remaining costs in Account 456 are miscellaneous.

7.5.2.4 Functionalization of Account 456.1 "Transmission of Power for Others"

Account 456.1 was established by FERC to account for wheeling revenues. This account continues to use the Direct Transmission functionalization for wheeling revenues. Account 456.1 was added to the FERC Uniform System of Accounts after the 1984 ASCM was approved.

7.5.3 Derivatives

A derivative is a financial instrument in which value depends on some underlying financial asset, commodity index, or predefined variable. Some of the main uses of derivative instruments are to fix future prices in the present (forwards and futures), to exchange cash flows or modify asset characteristics (swaps), and to endow the holder with the right, but not the obligation, to engage in a transaction (options).[2] The main types of derivatives used in the utility industry include futures, forwards, options, and swaps associated with the purchase or sale of power and fuel. Utilities are required to book assets and liabilities related to derivatives on their balance sheets.

Derivative accounts were functionalized to Distribution in the WP-07 Final Proposal. In addition, derivatives were discussed the Final WPRDS, WP-07-FS-BPA-05, section 2.19.1.1.2. BPA functionalizes derivative accounts to Production for purposes of calculating backcast ASCs. Derivative accounts are another example of additions to the FERC Uniform System of Accounts that were made after the 1984 ASCM was approved and therefore required changes to the ASC Cookbook model.

All derivative accounts listed in the FERC System of accounts have been incorporated. These include:

7.5.3.1 Derivative Assets

- Account 175, “Long-Term Portion of Derivative Assets”
- Account 176, “Long-Term Portion of Derivative Assets-Hedges”
- Account 176, “Less: Long-Term Portion of Derivative Assets-Hedges”

[2] Guide to the International Banking Statistics, Page 65. July 2000 - Bank for International Settlements Monetary and Economic Department, Basel, Switzerland.

7.5.3.2 Derivative Liabilities

- Account 244, "Long-Term Portion of Derivative Instruments Liabilities"
- Account 245, "Long-Term Portion of Derivative Instruments-Hedges Liabilities"
- Account 245, "Less: Long-Term Portion of Derivative Instruments-Hedges Liabilities"

7.5.4 Oregon Public Purpose Charges and Conservation

The State of Oregon passed legislation in 1999 that mandates utility customers be charged three percent of the total retail revenues of electric and gas utilities that operate in Oregon, to be used to develop comprehensive conservation and renewable resource programs. These conservation and renewables programs are operated by other organizations and not by PGE and PacifiCorp. This surcharge, known as the Oregon Public Purpose Charge (OPPC), funds conservation and other renewables projects conducted within the service territories of the applicable utilities. The OPPC effectively replaces the conservation programs within the state of Oregon for Portland General Electric and PacifiCorp (Oregon). BPA includes the OPPC as a conservation cost of the Oregon utilities for purposes of determining the backcast ASC.

Without accounting data from the organizations implementing the conservation and renewable resource programs funded by the OPPC, it is very difficult to determine how this charge would be capitalized and amortized over time. Therefore, BPA treats this charge as an expense for each year of the backcast.

Under the 1984 ASC Methodology, conservation is generally functionalized to production. However, the 1984 ASC Methodology specifies that advertising costs and costs associated with Model Conservation Standards be excluded. BPA has limited information about what portion of the OPPC funds are used for these non-exchangeable purposes. To account for costs such as advertising and Model Conservation Standards, 70 percent of the costs is functionalized to production and the remaining 30 percent is functionalized to distribution.

7.5.5 Conservation Costs

The FERC Form 1 does not contain adequate detail concerning conservation program costs to determine exchangeable and non-exchangeable costs. Therefore, to be consistent with the treatment of the OPPC discussed above, BPA uses a new functionalization ratio called "direct conservation" or DIR-C. This functionalization code allocates 70 percent of conservation cost to production and 30 percent to distribution.

7.5.6 Common Plant

Common utility plant is property plant and equipment that is shared between the electric and retail gas operations of a utility. For shared plant, there needs to be a line that is discernable between the electric and gas operations of the utility in order to calculate the exchangeable electric operations costs.

BPA functionalizes common utility plant using the Production/Transmission/Distribution (PTD) ratio. The revised 1984 ASC Cookbook includes the Accumulated Provision for Depreciation, Amortization, & Depletion of Common Plant in the Account 108, "Depreciation Reserve."

7.5.7 Acquisition Adjustments

Acquisition Adjustments represent the difference between the book value of acquired utility plant and the purchase price of the utility plant acquisition.

Acquisition adjustments are functionalized to production. This treatment recognizes that regional utilities are investing in generation projects by either building new plants or buying shares of new or established generation plants.

7.5.8 Functionalization of Property Taxes

BPA changed the functionalization of property taxes that are assessed to production assets that are outside a utility's service territory. Property taxes are generally functionalized using the Production/Transmission/Distribution/General (PTDG) ratio. Property taxes in states where a utility has service territory continue to be functionalized by PTDG. For property taxes in states where the utility has a generating facility that is outside the service territory, the functionalization is to Direct Production. An example of this is the Colstrip power plant, located in Montana, where the participating utilities do not have service territory in Montana, yet include Montana property taxes on their FERC Form 1.

The FERC Form 1 for each utility was reviewed to identify in which states there was retail service territory. In addition, the property taxes of each utility were reviewed to determine which property taxes were paid to states outside its service territory. The production assets of the utilities were then reviewed to determine if the taxes outside of their service territory were in states where the utility has a production plant.

7.6 Line Item Changes

The 1984 ASC Cookbook was revised to conform to the FERC Form 1 line items. Listed below are changes to the ASC Cookbook that were not discussed above.

7.6.1 Deletions of Line Items

The following line items were deleted:

7.6.1.1 Schedule 1: Plant Investment/Rate Base

- Duplicated lines for "Other Production Plant," Accounts 340-346
- All lines within General Plant that have the 10 percent TD functionalization
- Duplicated line items for "Other Production" in the Amortization and Depreciation reserve section, Account 108
- "Other Transmission Plant" line items in the Amortization and Depreciation reserve section, Account 108
- "Other Amortization" in the Amortization and Depreciation reserve section, Account 108
- "Amort. Reserve" in the Amortization and Depreciation reserve section, Account 111
- "Investments," Account 123
- "Weatherization Investment" within the Deferred Debits (this is included within Regulatory assets)
- "Interest and Dividend Receivable" within the Deferred Debits section
- "Other Credits" within the Deferred Credits section

7.6.1.2 Schedule 3: Expenses

- All lines that are "Other Prod" within Production Expenses
- All lines that are "Other Trans" within Production Expenses
- All lines that are "Other Dist" within Production Expenses
- All lines within Administration & General Expense section, with the 10 percent TD functionalization
- All lines that are "Other A&G" within Administration & General Expense section
- "Other Depreciation Exp" within the Depreciation and Amortization Expenses

- "Amort. of Limited Term Plant" within the Depreciation and Amortization Expenses
- "Amort. of Prop. Losses" within the Depreciation and Amortization Expenses
- "Amort. of Regulatory Assets" within the Depreciation and Amortization Expenses
- All "Other Amort." within the Depreciation and Amortization Expenses
- "In-lieu Taxes" was removed as a line item, as well as the section that calculated this line item
- "Non-Firm Sales for Resale" within the Other Included Item section
- "Billing Credits" in the Other Revenue Section
- All "Other Revenue" in the Other Revenue Section

7.6.2 Addition of Line Items

The following line items were added:

7.6.2.1 Schedule 1: Plant Investment/Rate Base

- "Accum. Prov for Depr, Amort, and Depl. Commn Plt" Line item is discussed above and functionalized using PTDG ratio
- "Accum. Prov for Depr, Amort, and Depl.: Other Utl Plt: Electric" functionalized using PTD ratio
- "Amort. of Plant Acquisition Adjustment (Electric)" functionalized to Production
- "(Utility Plant) In Service (Classified) Common," functionalized on the PTD ratio
- "Other Materials and Supplies" Account 156, functionalized on the PTDG ratio
- "Stores Expense Undistributed" Account 163, functionalized on the PTD ratio
- "Preliminary Survey and Investigation Charges Electric," Account 183, functionalized to Distribution
- "Preliminary Natural Gas Survey and Investigation Charges," Account 183.1, functionalized to Distribution

- “Other Preliminary Survey and Investigation Charges,” Account 183.2, functionalized to Distribution
- “Temporary Facilities,” Account 185, functionalized with the PTDG ratio
- “Deferred Losses from Disposition of Utility Plant,” Account 187, functionalized with the PTD ratio
- “Research, Development and Demonstration Expenditures,” Account 188, functionalized to Distribution
- “Unamortized Loss on Reacquired Debt,” Account 189, functionalized with the PTDG ratio
- “Accumulated Deferred Income Taxes,” Account 190, functionalized to Distribution
- “Unrecovered Purchased Gas Costs,” Account 191, functionalized to Production
- “Other Regulatory Liabilities” functionalized using Direct Analysis

7.6.2.2 Schedule 3: Expenses

- “BPA REP Reversal” functionalized to Production
- “Oregon Public Purposes Charge” functionalized using the DIR-C functionalization ratio as discussed above
- “Common Plant – Electric” within the Depreciation and Amortization Section PTD

7.6.2.3 Schedule 3B: Other Included Items

- Renamed Account 411.6 located in the Other Included Items to “(Less) Gain from Disp. of Plant”
- Renamed Account 447 located in Sales for Resale section to “Sales for Resale”
- “Revenues from Transmission of Electricity of Other,” Account 456.1, functionalized to Transmission as discussed above
- “Regional Control Service Revenues,” Account 457.1, functionalized to Transmission

- “Miscellaneous Revenues,” Account 457.2, functionalized to Transmission

7.6.3 Functionalization Changes

BPA changed functionalization of the following accounts in addition to those discussed above. The changes are due to error corrections, general updates, and changes in assumption based on new or better information. The abbreviations used in the descriptions are as follows:

Functionalized to Production (direct):	DIR-P
Functionalized to Transmission (direct):	DIR-D
Functionalized to Distribution (direct):	DIR-D
Functionalized to General:	G
Production, Transmission, and Distribution (ratio):	PTD

7.6.3.1 Schedule 1: Plant Investment/Rate Base

- Account 398, “Miscellaneous Equipment,” change functionalization from DIR-D to PTD
- Account 105, “Plant Held for Future Use,” change functionalization from PTD to PTDG
- Account 154, “Plant Materials and Operating Supplies,” change fnctionalization from TDG to PTD
- Account 184, “Clearing Accounts,” change functionalization from Labor to DIR-D
- Account 186, “Miscellaneous Deferred Debits,” change functionalization from Labor to Direct Analysis
- Account 256, “Deferred Gains from Disposition of Utility Plant,” change functionalization from TDG to PTD
- Account 253, “Other Deferred Credits,” change functionalization from DIR-D to Direct Analysis

7.6.3.2 Schedule 3: Expenses

- Account 922, "(Less) Administration Expenses Transferred Credit," change functionalization from Labor to PTD
- Account 923, "Outside Services Employed," change functionalization from Labor to PTD
- Account 929, "(Less) Duplicate Charges – Credit," change functionalization from Labor to PTDG
- Account 930.2, "Miscellaneous General Expenses," change functionalization from DIR-D to PTD
- Account 931, "Rents," change functionalization from DIR-D to PTD

7.6.4 PacifiCorp Inter-Jurisdictional Cost Allocation

PacifiCorp's costs are allocated to Idaho, Oregon, and Washington. The allocation reflects how PacifiCorp would have filed for ASCs if there had been an active REP. PacifiCorp's costs were allocated based on the Inter-Jurisdictional Cost Allocation System developed jointly by most of the state commissions that regulate PacifiCorp.

In addition, BPA used PacifiCorp's Oregon Jurisdiction Results of Operations filings to the Oregon Public Utility Commission for 2002, 2004, and 2006. The Results of Operations filings were used to develop allocation factors for rate base and costs that were directly allocated to each state. The 2003 allocation factors for direct allocation to each state were developed from the 2002 Results of Operations filing. This process was replicated for 2005. In addition, the Results of Operations filings were used to match the allocation factors that were provided by PacifiCorp to the corresponding accounts in the ASC Cookbook model. The total costs in each account were then multiplied by the individual state allocation factors to produce costs for Oregon, Washington, and Idaho.

BPA corrected the PacifiCorp regional cookbook files to be the total of Oregon, Washington, and Idaho for all accounts. In addition, BPA corrected PacifiCorp's General Plant (GP) ratio by including Account 399, Mining Assets, in the ratio determination.

7.6.5 Reversal of Purchase Power Expense

Puget Sound and PacifiCorp recorded negative purchase power expenses in the FERC Form 1 to account for the benefits paid by BPA under the REP Settlements. BPA removed these negative entries.

Portland General Electric included the BPA power sale in its power purchases at BPA's RL rate. BPA removed the power purchase at the RL rate and replaced it with purchases at market rates. The effect of this adjustment is to increase PGE's cost of purchase power.

7.7 Summary of Backcast ASCs For FY 2002-2006

Table 7.1 summarizes the backcast ASC determinations by utility for FY 2002-2006. Following Table 7.1 are two-page summaries of each utility's ASC calculation for the years 2002 through 2006.

TABLE 7.1
Backcast ASCs – FY 2002-2006
($/MWh)

	2002	2003	2004	2005	2006
Avista	44.38	44.54	45.77	42.37	44.40
Idaho Power	44.65	37.39	34.07	33.07	27.86
NorthWestern Energy	46.99	46.99	50.43	47.50	52.62
PacifiCorp - Regional	37.38	36.83	39.52	40.76	41.06
PacifiCorp - ID	33.32	33.16	34.18	36.60	38.61
PacifiCorp - OR	38.42	38.11	41.43	42.68	42.07
PacifiCorp - WA	37.29	35.67	37.62	37.95	39.66
Portland General	52.54	47.16	44.30	46.99	49.72
Puget Sound	48.05	45.41	46.50	50.21	55.32

Table 7.1 Avista 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$26,239,075	$11,203,872	$4,466,267	$10,568,936
Total Production Plant	740,735,723	740,735,723	-	-
Total Transmission Plant	295,283,980	-	295,283,980	-
Total Distribution Plant	698,757,399	-	-	698,757,399
Total General Plant	48,474,712	10,600,221	11,244,331	26,630,160
Total Electric Plant In-Service	1,809,490,889	762,539,816	310,994,579	735,956,494
LESS:				
Total Depreciation and Amortization	639,181,621	281,403,340	120,865,135	236,913,146
Total Net Plant	1,170,309,268	481,136,476	190,129,444	499,043,348
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	29,849,502	19,832,008	2,447,511	7,569,983
Total Utility Plant	119,728,736	44,900,684	17,899,032	56,929,020
Total Other Property and Investments	46,498,833	-	-	46,498,833
Total Current and Accrued Assets	75,443,963	68,647,708	2,018,855	4,777,400
Total Deferred Debits	443,938,853	210,252,910	10,306,674	223,379,269
Total Assets and Other Debits	715,459,887	343,633,311	32,672,072	339,154,504
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	50,057,633	50,057,633	-	-
Total Deferred Credits	535,788,341	34,996,533	3,899,825	496,891,983
Total Liabilities and Other Credits	585,845,974	85,054,166	3,899,825	496,891,983
Total Rate Base	1,299,923,181	739,715,620	218,901,691	341,305,870
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$1,105,078,874
Interest for Year	93,183,757
Rate of Return	8.43%
(Interest/Long Term Debt)	

Table 7.1 Avista 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$276,115,311	$276,115,311	$0	$0
Total Transmission Expense	13,592,302	-	13,592,302	-
Total Distribution Expense	14,320,185	-	-	14,320,185
Total Customer and Sales Expenses	23,375,746	-	-	23,375,746
Total Administration and General Expenses	46,173,337	17,321,619	5,987,786	22,863,931
Total Operations and Maintenance	373,576,881	293,436,930	19,580,088	60,559,862
Total Depreciation and Amortization	53,677,906	24,812,307	9,064,394	19,801,205
Schedule 3A Items: Taxes				
Total Federal	5,859,037	3,087,798	897,625	1,873,615
Total State	49,871,419	12,215,733	2,591,720	35,063,966
Total County and Municipal	15,957,107	6,318,154	1,836,691	7,802,262
Total Taxes	71,687,563	21,621,685	5,326,036	44,739,842
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	64,082,272	64,082,272	-	-
Total Other Revenues	55,491,115	17,577,365	18,957,278	18,956,473
Total Other Included Items	119,573,387	81,659,637	18,957,278	18,956,473
Schedule 4: Average System Cost				
Total Operating Expenses	379,368,963	258,211,286	15,013,240	106,144,437
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	109,613,647	62,375,168	18,458,485	28,779,994
*(Total Rate Base * Rate of Return)*				
Total Cost	$488,982,610	$320,586,454	$33,471,725	$134,924,431
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$354,058,179
Total Retail Load (MWH)	7,598,029
Distribution Losses	379,901
Total Retail Load plus Distribution Losses	7,977,930
Average System Cost before NLSL Adjustment	**$44.38**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$44.38**
Contract System Costs	$354,058,179
Contract System Load	7,977,930
Average System Cost (See note below)	**$44.38**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.1.1 Avista 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$26,484,820	$12,001,902	$4,290,864	$10,192,055
Total Production Plant	852,627,548	852,627,548	-	-
Total Transmission Plant	304,827,401	-	304,827,401	-
Total Distribution Plant	724,054,166	-	-	724,054,166
Total General Plant	52,183,500	12,390,123	11,779,717	28,013,660
Total Electric Plant In-Service	1,960,177,435	877,019,573	320,897,982	762,259,881
LESS:				
Total Depreciation and Amortization	686,989,565	305,818,974	128,271,374	252,899,217
Total Net Plant	1,273,187,870	571,200,599	192,626,608	509,360,663
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	30,803,571	20,321,811	2,600,835	7,880,925
Total Utility Plant	156,734,762	50,946,291	18,214,079	87,574,392
Total Other Property and Investments	55,738,128	-	-	55,738,128
Total Current and Accrued Assets	51,989,612	46,469,555	1,635,431	3,884,626
Total Deferred Debits	438,013,241	213,125,605	9,683,157	215,204,479
Total Assets and Other Debits	733,279,314	330,863,262	32,133,502	370,282,551
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	36,057,271	36,057,271	-	-
Total Deferred Credits	566,645,699	29,741,678	3,882,510	533,021,511
Total Liabilities and Other Credits	602,702,970	65,798,949	3,882,510	533,021,511
Total Rate Base	1,403,764,214	836,264,912	220,877,599	346,621,703
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$1,122,669,487
Interest for Year	82,856,279
Rate of Return	7.38%
(Interest/Long Term Debt)	

Table 7.1.1 Avista 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$329,682,924	$329,682,924	$0	$0
Total Transmission Expense	14,989,464	-	14,989,464	-
Total Distribution Expense	16,539,116	-	-	16,539,116
Total Customer and Sales Expenses	23,555,750	-	-	23,555,750
Total Administration and General Expenses	47,379,256	18,609,502	5,817,216	22,952,538
Total Operations and Maintenance	432,146,510	348,292,426	20,806,680	63,047,404
Total Depreciation and Amortization	57,368,348	28,070,204	9,192,603	20,105,541
Schedule 3A Items: Taxes				
Total Federal	3,352,764	3,701,840	999,866	(1,348,942)
Total State	47,296,247	13,513,859	2,729,452	31,052,936
Total County and Municipal	15,105,721	6,085,631	1,643,728	7,376,362
Total Taxes	65,754,732	23,301,330	5,373,045	37,080,357
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	80,710,417	80,710,417	-	-
Total Other Revenues	87,425,855	32,922,947	23,321,135	31,181,774
Total Other Included Items	168,136,272	113,633,364	23,321,135	31,181,774
Schedule 4: Average System Cost				
Total Operating Expenses	387,133,318	286,030,597	12,051,193	89,051,528
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	103,601,889	61,718,787	16,301,410	25,581,692
*(Total Rate Base * Rate of Return)*				
Total Cost	$490,735,207	$347,749,384	$28,352,603	$114,633,219
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$376,101,987
Total Retail Load (MWH)	8,041,166
Distribution Losses	402,058
Total Retail Load plus Distribution Losses	8,443,224
Average System Cost before NLSL Adjustment	**$44.54**
New Large Single Load(s) (MWH)	29,367.82
Cost of Serving New Large Single Load(s)	$1,308,185
Average System Cost after NLSL Adjustment	**$44.54**
Contract System Costs	$374,793,803
Contract System Load	8,413,856
Average System Cost (See note below)	**$44.54**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.1.2 Avista 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$27,037,661	$11,902,632	$4,654,029	$10,480,999
Total Production Plant	863,539,966	863,539,966	-	-
Total Transmission Plant	337,651,373	-	337,651,373	-
Total Distribution Plant	760,400,014	-	-	760,400,014
Total General Plant	53,766,005	12,894,175	12,558,274	28,313,556
Total Electric Plant In-Service	2,042,395,019	888,336,774	354,863,676	799,194,569
LESS:				
Total Depreciation and Amortization	715,663,333	316,344,244	134,349,766	264,969,322
Total Net Plant	1,326,731,686	571,992,529	220,513,909	534,225,247
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	32,935,455	21,395,630	2,839,136	8,700,689
Total Utility Plant	129,233,967	39,962,528	15,625,684	73,645,755
Total Other Property and Investments	93,007,135	55,824,772	-	37,182,363
Total Current and Accrued Assets	27,952,949	20,281,539	2,358,963	5,312,447
Total Deferred Debits	428,982,406	193,721,137	11,148,765	224,112,504
Total Assets and Other Debits	712,111,912	331,185,606	31,972,548	348,953,759
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	39,971,987	39,971,987	-	-
Total Current and Accrued Liabilities	5,712,950	5,712,950	-	-
Total Deferred Credits	601,471,693	47,463,751	4,240,499	549,767,443
Total Liabilities and Other Credits	647,156,630	93,148,688	4,240,499	549,767,443
Total Rate Base	1,391,686,968	810,029,447	248,245,958	333,411,563
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$1,133,530,068
Interest for Year	79,197,611
Rate of Return	6.99%
(Interest/Long Term Debt)	

Table 7.1.2 Avista 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$364,036,052	$364,036,052	$0	$0
Total Transmission Expense	16,115,328	-	16,115,328	-
Total Distribution Expense	19,108,033	-	-	19,108,033
Total Customer and Sales Expenses	25,629,327	-	-	25,629,327
Total Administration and General Expenses	51,165,545	19,699,628	6,597,762	24,868,155
Total Operations and Maintenance	476,054,285	383,735,680	22,713,090	69,605,515
Total Depreciation and Amortization	57,428,642	28,615,880	9,400,588	19,412,174
Schedule 3A Items: Taxes				
Total Federal	13,919,572	3,143,646	903,563	9,872,363
Total State	46,910,425	13,372,538	2,746,405	30,791,482
Total County and Municipal	16,051,765	6,458,245	1,856,263	7,737,257
Total Taxes	76,881,762	22,974,429	5,506,231	48,401,102
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	89,993,250	89,993,250	-	-
Total Other Revenues	82,389,299	28,407,430	25,957,919	28,023,951
Total Other Included Items	172,382,549	118,400,680	25,957,919	28,023,951
Schedule 4: Average System Cost				
Total Operating Expenses	437,982,140	316,925,310	11,661,990	109,394,840
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	97,234,547	56,595,232	17,344,478	23,294,838
*(Total Rate Base * Rate of Return)*				
Total Cost	$535,216,687	$373,520,542	$29,006,467	$132,689,678
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$402,527,009
Total Retail Load (MWH)	8,376,616
Distribution Losses	418,831
Total Retail Load plus Distribution Losses	8,795,447
Average System Cost before NLSL Adjustment	**$45.77**
New Large Single Load(s) (MWH)	17,835.14
Cost of Serving New Large Single Load(s)	$816,232
Average System Cost after NLSL Adjustment	**$45.77**
Contract System Costs	$401,710,777
Contract System Load	8,777,612
Average System Cost (See note below)	**$45.77**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.1.3 Avista 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$27,115,071	$12,474,446	$4,663,598	$9,977,027
Total Production Plant	988,538,283	988,538,283	-	-
Total Transmission Plant	369,567,144	-	369,567,144	-
Total Distribution Plant	790,630,169	-	-	790,630,169
Total General Plant	60,419,320	16,008,598	14,135,365	30,275,356
Total Electric Plant In-Service	2,236,269,987	1,017,021,327	388,366,107	830,882,552
LESS:				
Total Depreciation and Amortization	761,957,388	340,625,585	143,321,571	278,010,232
Total Net Plant	1,474,312,599	676,395,742	245,044,537	552,872,320
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	26,756,301	15,089,003	2,855,729	8,811,569
Total Utility Plant	159,863,306	54,108,289	20,228,499	85,526,517
Total Other Property and Investments	80,432,811	46,731,530	-	33,701,281
Total Current and Accrued Assets	89,017,914	80,513,020	2,709,133	5,795,760
Total Deferred Debits	403,526,254	235,705,916	23,361,156	144,459,182
Total Assets and Other Debits	759,596,586	432,147,758	49,154,518	278,294,309
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	10,044,751	10,044,751	-	-
Total Current and Accrued Liabilities	3,446,699	3,446,699	-	-
Total Deferred Credits	675,181,617	130,332,756	4,825,347	540,023,514
Total Liabilities and Other Credits	688,673,067	143,824,206	4,825,347	540,023,514
Total Rate Base	1,545,236,118	964,719,295	289,373,708	291,143,115
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$1,225,824,323
Interest for Year	80,470,939
Rate of Return	6.56%

(Interest/Long Term Debt)

Table 7.1.3 Avista 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$452,344,552	$452,344,552	$0	$0
Total Transmission Expense	16,327,683	-	16,327,683	-
Total Distribution Expense	21,239,624	-	-	21,239,624
Total Customer and Sales Expenses	24,680,467	-	-	24,680,467
Total Administration and General Expenses	50,834,871	19,744,261	6,518,151	24,572,458
Total Operations and Maintenance	565,427,197	472,088,813	22,845,834	70,492,549
Total Depreciation and Amortization	64,877,706	33,393,276	10,467,386	21,017,044
Schedule 3A Items: Taxes				
Total Federal	31,348,483	3,127,687	902,162	27,318,634
Total State	67,483,947	14,516,937	2,840,284	50,126,726
Total County and Municipal	21,349	-	-	21,349
Total Taxes	98,853,779	17,644,624	3,742,445	77,466,709
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	221,803,806	221,803,806	-	-
Total Other Revenues	60,058,249	21,021,843	19,457,021	19,579,385
Total Other Included Items	281,862,055	242,825,649	19,457,021	19,579,385
Schedule 4: Average System Cost				
Total Operating Expenses	447,296,627	280,301,065	17,598,645	149,396,917
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	101,439,170	63,330,337	18,996,339	19,112,494
*(Total Rate Base * Rate of Return)*				
Total Cost	$548,735,797	$343,631,402	$36,594,984	$168,509,411
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$380,226,386
Total Retail Load (MWH)	8,542,674
Distribution Losses	427,134
Total Retail Load plus Distribution Losses	8,969,808
Average System Cost before NLSL Adjustment	**$42.39**
New Large Single Load(s) (MWH)	37,454.82
Cost of Serving New Large Single Load(s)	$1,747,441
Average System Cost after NLSL Adjustment	**$42.37**
Contract System Costs	$378,478,945
Contract System Load	8,932,353
Average System Cost (See note below)	**$42.37**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.1.4 Avista 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$19,679,401	$8,840,788	$3,421,380	$7,417,233
Total Production Plant	991,794,149	991,794,149	-	-
Total Transmission Plant	383,823,745	-	383,823,745	-
Total Distribution Plant	832,094,240	-	-	832,094,240
Total General Plant	64,737,335	16,517,699	15,210,483	33,009,153
Total Electric Plant In-Service	2,292,128,870	1,017,152,636	402,455,607	872,520,627
LESS:				
Total Depreciation and Amortization	801,728,444	362,220,710	151,541,818	287,965,916
Total Net Plant	1,490,400,426	654,931,926	250,913,789	584,554,711
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	29,680,030	17,456,911	3,282,132	8,940,988
Total Utility Plant	166,858,770	40,781,026	15,782,233	110,295,511
Total Other Property and Investments	56,740,866	25,574,531	-	31,166,335
Total Current and Accrued Assets	33,437,261	22,153,845	3,561,789	7,721,627
Total Deferred Debits	484,199,368	219,974,498	16,615,711	247,609,159
Total Assets and Other Debits	770,916,295	325,940,811	39,241,865	405,733,619
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	15,318,835	15,318,835	-	-
Total Current and Accrued Liabilities	73,478,456	73,478,456	-	-
Total Deferred Credits	576,833,230	30,479,769	4,506,457	541,847,005
Total Liabilities and Other Credits	665,630,521	119,277,060	4,506,457	541,847,005
Total Rate Base	1,595,686,200	861,595,677	285,649,198	448,441,325
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$1,116,000,333
Interest for Year	85,054,979
Rate of Return	7.62%
(Interest/Long Term Debt)	

Table 7.1.4 Avista 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$431,008,791	$431,008,791	$0	$0
Total Transmission Expense	19,547,280	-	19,547,280	-
Total Distribution Expense	22,569,058	-	-	22,569,058
Total Customer and Sales Expenses	25,860,122	-	-	25,860,122
Total Administration and General Expenses	49,517,622	19,709,124	6,709,778	23,098,720
Total Operations and Maintenance	548,502,873	450,717,915	26,257,058	71,527,900
Total Depreciation and Amortization	67,390,752	34,645,027	11,018,514	21,727,211
Schedule 3A Items: Taxes				
Total Federal	55,538,224	3,163,380	939,446	51,435,398
Total State	76,261,914	13,368,840	2,668,025	60,225,049
Total County and Municipal	11,907	-	-	11,907
Total Taxes	131,812,045	16,532,220	3,607,471	111,672,354
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	175,572,595	175,572,595	-	-
Total Other Revenues	66,996,908	23,573,156	20,750,730	22,673,022
Total Other Included Items	242,569,503	199,145,751	20,750,730	22,673,022
Schedule 4: Average System Cost				
Total Operating Expenses	505,136,167	302,749,412	20,132,312	182,254,443
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	121,613,813	65,665,753	21,770,501	34,177,559
*(Total Rate Base * Rate of Return)*				
Total Cost	$626,749,980	$368,415,165	$41,902,813	$216,432,002
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$410,317,978
Total Retail Load (MWH)	8,787,002
Distribution Losses	439,350
Total Retail Load plus Distribution Losses	9,226,352
Average System Cost before NLSL Adjustment	**$44.47**
New Large Single Load(s) (MWH)	61,449.46
Cost of Serving New Large Single Load(s)	$3,398,696
Average System Cost after NLSL Adjustment	**$44.40**
Contract System Costs	$406,919,282
Contract System Load	9,164,903
Average System Cost (See note below)	**$44.40**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.2 Idaho Power 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$67,128,967	$34,103,199	$11,545,521	$21,480,248
Total Production Plant	1,433,626,812	1,433,626,812	-	-
Total Transmission Plant	485,349,425	-	485,349,425	-
Total Distribution Plant	902,984,488	-	-	902,984,488
Total General Plant	198,329,401	73,175,605	44,187,178	80,966,618
Total Electric Plant In-Service	3,087,419,093	1,540,905,616	541,082,123	1,005,431,354
LESS:				
Total Depreciation and Amortization	1,294,961,078	707,757,601	203,077,737	384,125,740
Total Net Plant	1,792,458,015	833,148,015	338,004,386	621,305,614
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	46,996,594	31,992,751	3,473,191	11,530,652
Total Utility Plant	94,362,283	710,969	409,231	93,242,082
Total Other Property and Investments	26,881	-	-	26,881
Total Current and Accrued Assets	61,219,932	34,517,003	9,335,111	17,367,818
Total Deferred Debits	650,062,474	237,551,964	18,699,819	393,810,690
Total Assets and Other Debits	852,668,164	852,668,165	852,668,166	852,668,167
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	91,235	91,235	-	-
Total Deferred Credits	800,417,308	28,419,087	7,716,847	764,281,374
Total Liabilities and Other Credits	800,508,543	28,510,322	7,716,847	764,281,374
Total Rate Base	1,844,617,636	1,109,410,380	362,204,893	373,002,363
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$953,229,728
Interest for Year	51,127,384
Rate of Return	5.36%
(Interest/Long Term Debt)	

Table 7.2 Idaho Power 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$475,199,888	$475,199,888	$0	$0
Total Transmission Expense	15,459,670	-	15,459,670	-
Total Distribution Expense	41,943,849	-	-	41,943,849
Total Customer and Sales Expenses	25,011,421	-	-	25,011,421
Total Administration and General Expenses	63,330,753	25,714,948	12,325,860	25,289,945
Total Operations and Maintenance	620,945,581	500,914,836	27,785,530	92,245,215
Total Depreciation and Amortization	93,712,973	44,431,707	14,167,874	35,113,392
Schedule 3A Items: Taxes				
Total Federal	(16,894,561)	3,724,860	1,702,500	(22,321,922)
Total State	24,166,382	9,233,138	2,517,786	12,415,459
Total County and Municipal	-	-	-	-
Total Taxes	7,271,821	12,957,998	4,220,286	(9,906,463)
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	12,328	6,153	2,161	4,015
Total Sales from Resale	55,031,087	55,031,087	-	-
Total Other Revenues	39,981,570	508,484	23,288,535	16,184,551
Total Other Included Items	95,024,985	55,545,724	23,290,696	16,188,566
Schedule 4: Average System Cost				
Total Operating Expenses	626,905,390	502,758,818	22,882,994	101,263,578
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	98,937,823	59,504,282	19,427,204	20,006,337
*(Total Rate Base * Rate of Return)*				
Total Cost	$725,843,213	$562,263,100	$42,310,198	$121,269,915
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$604,573,298
Total Retail Load (MWH)	12,894,068
Distribution Losses	644,703
Total Retail Load plus Distribution Losses	13,538,771
Average System Cost before NLSL Adjustment	**$44.65**
New Large Single Load(s) (MWH)	306,600.00
Cost of Serving New Large Single Load(s)	$13,691,227
Average System Cost after NLSL Adjustment	**$44.65**
Contract System Costs	$590,882,071
Contract System Load	13,232,171
Average System Cost (See note below)	**$44.65**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.2.1 Idaho Power 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$71,794,683	$35,617,292	$12,880,486	$23,296,905
Total Production Plant	1,456,953,896	1,456,953,896	-	-
Total Transmission Plant	526,886,598	-	526,886,598	-
Total Distribution Plant	952,978,561	-	-	952,978,561
Total General Plant	212,069,129	48,474,713	48,474,714	48,474,715
Total Electric Plant In-Service	3,220,682,867	1,570,445,340	588,034,930	1,062,202,597
LESS:				
Total Depreciation and Amortization	1,239,604,536	616,549,083	210,519,937	412,535,516
Total Net Plant	1,981,078,331	953,896,257	377,514,993	649,667,081
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	36,198,855	20,140,483	4,061,606	11,996,766
Total Utility Plant	98,069,626	734,312	445,118	96,890,197
Total Other Property and Investments	14,225	-	-	14,225
Total Current and Accrued Assets	52,818,063	29,341,401	8,358,558	15,118,104
Total Deferred Debits	616,257,810	174,381,203	20,675,260	421,201,347
Total Assets and Other Debits	803,358,579	224,597,399	33,540,541	545,220,639
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	-	-	-	-
Total Deferred Credits	1,867,932,822	101,228,014	34,306,972	1,732,397,837
Total Liabilities and Other Credits	1,867,932,822	101,228,014	34,306,972	1,732,397,837
Total Rate Base	916,504,088	1,077,265,642	376,748,563	(537,510,117)
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$933,150,015
Interest for Year	54,645,483
Rate of Return	5.86%
(Interest/Long Term Debt)	

Table 7.2.1 Idaho Power 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$385,970,436	$385,970,436	$0	$0
Total Transmission Expense	19,512,743	-	19,512,743	-
Total Distribution Expense	44,043,908	-	-	44,043,908
Total Customer and Sales Expenses	25,939,434	-	-	25,939,434
Total Administration and General Expenses	65,001,923	26,031,032	12,980,105	25,990,786
Total Operations and Maintenance	540,468,444	412,001,468	32,492,848	95,974,128
Total Depreciation and Amortization	97,760,033	45,575,475	15,091,615	37,092,942
Schedule 3A Items: Taxes				
Total Federal	99,392,740	3,633,002	1,692,396	94,067,342
Total State	26,616,074	9,234,093	2,721,506	14,660,475
Total County and Municipal	-	-	-	-
Total Taxes	126,008,814	12,867,095	4,413,902	108,727,817
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	20,012	9,758	3,654	6,600
Total Sales from Resale	71,572,857	71,572,857	-	-
Total Other Revenues	39,354,512	147,715	24,427,485	14,779,312
Total Other Included Items	110,947,381	71,730,330	24,431,138	14,785,912
Schedule 4: Average System Cost				
Total Operating Expenses	653,289,910	398,713,708	27,567,227	227,008,976
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	53,670,694	63,084,928	22,062,484	(31,476,718)
*(Total Rate Base * Rate of Return)*				
Total Cost	$706,960,604	$461,798,635	$49,629,711	$195,532,258
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$511,428,346
Total Retail Load (MWH)	12,980,031
Distribution Losses	649,002
Total Retail Load plus Distribution Losses	13,629,033
Average System Cost before NLSL Adjustment	**$37.52**
New Large Single Load(s) (MWH)	332,880.00
Cost of Serving New Large Single Load(s)	$14,350,370
Average System Cost after NLSL Adjustment	**$37.39**
Contract System Costs	$497,077,976
Contract System Load	13,296,153
Average System Cost (See note below)	**$37.39**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.2.2 Idaho Power 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$76,754,564	$37,491,726	$14,169,638	$25,093,200
Total Production Plant	1,482,517,098	1,482,517,098	-	-
Total Transmission Plant	560,303,124	-	560,303,124	-
Total Distribution Plant	992,248,198	-	-	992,248,198
Total General Plant	213,447,249	48,474,713	48,474,714	48,474,715
Total Electric Plant In-Service	3,325,270,233	1,592,410,121	621,228,486	1,111,631,626
LESS:				
Total Depreciation and Amortization	1,316,124,554	657,454,906	223,066,040	435,603,607
Total Net Plant	2,009,145,679	934,955,215	398,162,446	676,028,018
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	35,353,677	16,872,929	4,514,997	13,965,750
Total Utility Plant	153,832,980	807,744	492,405	152,532,832
Total Other Property and Investments	32,458,340	-	-	32,458,340
Total Current and Accrued Assets	61,051,812	33,166,075	10,063,735	17,822,002
Total Deferred Debits	617,804,386	136,834,000	19,971,781	460,998,605
Total Assets and Other Debits	900,501,195	852,668,165	852,668,166	852,668,167
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	445	445	-	-
Total Deferred Credits	961,026,762	113,036,668	35,214,359	812,775,735
Total Liabilities and Other Credits	961,027,207	113,037,113	35,214,359	812,775,735
Total Rate Base	1,948,619,667	1,009,598,850	397,991,005	541,029,812
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$987,045,000
Interest for Year	50,317,585
Rate of Return	5.10%
(Interest/Long Term Debt)	

Table 7.2.2 Idaho Power 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$407,579,274	$407,579,274	$0	$0
Total Transmission Expense	23,835,089	-	23,835,089	-
Total Distribution Expense	39,349,285	-	-	39,349,285
Total Customer and Sales Expenses	25,843,019	-	-	25,843,019
Total Administration and General Expenses	85,126,373	26,307,787	12,284,890	46,533,695
Total Operations and Maintenance	581,733,040	433,887,061	36,119,979	111,725,999
Total Depreciation and Amortization	101,037,621	47,308,408	17,521,822	36,207,392
Schedule 3A Items: Taxes				
Total Federal	41,150,426	2,818,967	1,267,183	37,064,275
Total State	22,970,647	8,824,407	2,700,405	11,445,836
Total County and Municipal	-	-	-	-
Total Taxes	64,121,073	11,643,374	3,967,588	48,510,111
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(2,071)	(992)	(387)	(692)
Total Sales from Resale	121,147,646	121,147,646	-	-
Total Other Revenues	42,724,578	2,018,555	23,523,292	17,182,731
Total Other Included Items	163,870,153	123,165,209	23,522,905	17,182,039
Schedule 4: Average System Costs				
Total Operating Expenses	583,021,581	369,673,634	34,086,484	179,261,463
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	99,336,743	51,467,335	20,288,787	27,580,620
*(Total Rate Base * Rate of Return)*				
Total Cost	$682,358,324	$421,140,969	$54,375,272	$206,842,083
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$475,516,241
Total Retail Load (MWH)	13,239,589
Distribution Losses	661,979
Total Retail Load plus Distribution Losses	13,901,568
Average System Cost before NLSL Adjustment	**$34.21**
New Large Single Load(s) (MWH)	367,920.00
Cost of Serving New Large Single Load(s)	$14,388,384
Average System Cost after NLSL Adjustment	**$34.07**
Contract System Costs	$461,127,857
Contract System Load	13,533,648
Average System Cost (See note below)	**$34.07**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.2.3 Idaho Power 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$69,742,756	$34,169,047	$12,687,771	$22,885,939
Total Production Plant	1,563,008,126	1,563,008,126	-	-
Total Transmission Plant	580,381,676	-	580,381,676	-
Total Distribution Plant	1,046,880,491	-	-	1,046,880,491
Total General Plant	217,508,189	48,474,713	48,474,714	48,474,715
Total Electric Plant In-Service	3,477,521,238	1,675,472,529	642,879,342	1,159,169,367
LESS:				
Total Depreciation and Amortization	1,364,640,116	690,005,169	226,645,040	447,989,907
Total Net Plant	2,112,881,122	985,467,361	416,234,302	711,179,459
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	29,917,143	13,386,874	4,659,211	11,871,058
Total Utility Plant	152,266,070	945,763	537,262	150,783,045
Total Other Property and Investments	1,025,159	-	-	1,025,159
Total Current and Accrued Assets	59,722,279	35,247,240	8,729,303	15,745,736
Total Deferred Debits	629,637,669	123,945,998	22,167,559	483,524,112
Total Assets and Other Debits	872,568,320	852,668,165	852,668,166	852,668,167
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	-	-	-	-
Total Deferred Credits	1,042,495,122	180,434,287	45,427,024	816,633,811
Total Liabilities and Other Credits	1,042,495,122	180,434,287	45,427,024	816,633,811
Total Rate Base	1,942,954,320	978,558,949	406,900,613	557,494,758
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$987,045,000
Interest for Year	53,339,531
Rate of Return	5.40%
(Interest/Long Term Debt)	

Table 7.2.3 Idaho Power 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$397,057,412	$397,057,412	$0	$0
Total Transmission Expense	21,989,736	-	21,989,736	-
Total Distribution Expense	38,324,600	-	-	38,324,600
Total Customer and Sales Expenses	25,714,779	-	-	25,714,779
Total Administration and General Expenses	81,724,444	35,511,407	15,283,951	30,929,086
Total Operations and Maintenance	564,810,971	432,568,819	37,273,687	94,968,465
Total Depreciation and Amortization	101,507,467	48,014,326	17,647,331	35,845,811
Schedule 3A Items: Taxes				
Total Federal	50,071,224	4,349,191	1,841,872	43,880,160
Total State	23,629,680	9,168,398	2,720,003	11,741,279
Total County and Municipal	-	-	-	-
Total Taxes	73,700,904	13,517,590	4,561,875	55,621,439
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	591	285	109	197
Total Sales from Resale	142,794,426	142,794,426	-	-
Total Other Revenues	38,611,625	199,361	21,275,041	17,137,223
Total Other Included Items	181,406,642	142,994,072	21,275,150	17,137,420
Schedule 4: Average System Cost				
Total Operating Expenses	558,612,700	351,106,662	38,207,743	169,298,295
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	104,996,502	52,880,948	21,988,752	30,126,802
*(Total Rate Base * Rate of Return)*				
Total Cost	$663,609,202	$403,987,610	$60,196,495	$199,425,097
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$464,184,105
Total Retail Load (MWH)	13,288,812
Distribution Losses	664,441
Total Retail Load plus Distribution Losses	13,953,253
Average System Cost before NLSL Adjustment	**$33.27**
New Large Single Load(s) (MWH)	367,920.00
Cost of Serving New Large Single Load(s)	$14,967,131
Average System Cost after NLSL Adjustment	**$33.07**
Contract System Costs	$449,216,975
Contract System Load	13,585,333
Average System Cost (See note below)	**$33.07**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.2.4 Idaho Power 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$72,094,030	$34,827,487	$13,271,332	$23,995,211
Total Production Plant	1,592,790,118	1,592,790,118	-	-
Total Transmission Plant	606,947,191	-	606,947,191	-
Total Distribution Plant	1,097,389,958	-	-	1,097,389,958
Total General Plant	214,927,062	48,474,713	48,474,714	48,474,715
Total Electric Plant In-Service	3,584,148,359	1,702,151,991	670,690,323	1,211,306,046
LESS:				
Total Depreciation and Amortization	1,406,209,952	710,134,157	236,761,039	459,314,756
Total Net Plant	2,177,938,407	992,017,834	433,929,284	751,991,290
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	29,153,644	11,278,671	5,218,293	12,656,680
Total Utility Plant	212,449,340	879,942	525,783	211,043,615
Total Other Property and Investments	3,696	-	-	3,696
Total Current and Accrued Assets	63,204,062	38,376,477	8,841,580	15,986,005
Total Deferred Debits	645,699,285	109,499,915	31,905,429	504,293,941
Total Assets and Other Debits	950,510,027	852,668,165	852,668,166	852,668,167
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	1,462,637	1,462,637	-	-
Total Deferred Credits	953,195,185	106,425,268	32,400,117	814,369,800
Total Liabilities and Other Credits	954,657,822	107,887,905	32,400,117	814,369,800
Total Rate Base	2,173,790,612	1,044,164,933	448,020,252	681,605,426
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$987,045,000
Interest for Year	53,744,453
Rate of Return	5.44%
(Interest/Long Term Debt)	

Table 7.2.4 Idaho Power 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$450,334,589	$450,263,162	$0	$71,427
Total Transmission Expense	23,669,858	-	23,669,858	-
Total Distribution Expense	41,984,481	-	-	41,984,481
Total Customer and Sales Expenses	28,971,362	-	-	28,971,362
Total Administration and General Expenses	86,726,893	38,424,236	18,076,487	30,226,170
Total Operations and Maintenance	631,687,183	488,687,398	41,746,345	101,253,440
Total Depreciation and Amortization	99,893,071	47,413,976	17,164,994	35,314,101
Schedule 3A Items: Taxes				
Total Federal	84,018,621	4,528,019	2,069,554	77,421,048
Total State	29,462,670	8,604,662	2,627,440	18,230,568
Total County and Municipal	-	-	-	-
Total Taxes	113,481,291	13,132,680	4,696,994	95,651,617
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(46,144)	(21,914)	(8,635)	(15,595)
Total Sales from Resale	260,717,491	260,717,491	-	-
Total Other Revenues	34,737,531	141,344	18,216,051	16,380,135
Total Other Included Items	295,408,878	260,836,921	18,207,416	16,364,540
Schedule 4: Average System Cost				
Total Operating Expenses	549,652,667	288,397,133	45,400,916	215,854,617
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	118,362,575	56,854,625	24,394,636	37,113,314
Total Cost	$668,015,242	$345,251,758	$69,795,552	$252,967,931
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$415,047,311
Total Retail Load (MWH)	13,939,314
Distribution Losses	696,966
Total Retail Load plus Distribution Losses	14,636,280
Average System Cost before NLSL Adjustment	**$28.36**
New Large Single Load(s) (MWH)	385,440.00
Cost of Serving New Large Single Load(s)	$17,948,434
Average System Cost after NLSL Adjustment	**$27.86**
Contract System Costs	$397,098,877
Contract System Load	14,250,840
Average System Cost (See note below)	**$27.86**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.3 NorthWestern 2003 for 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$2,238,806	$292,379	$739,066	$1,207,361
Total Production Plant	196,512,359	196,512,359	-	-
Total Transmission Plant	496,738,344	-	496,738,344	-
Total Distribution Plant	811,486,940	-	-	811,486,940
Total General Plant	66,444,171	4,968,799	23,365,493	38,109,879
Total Electric Plant In-Service	1,573,420,620	201,773,536	520,842,903	850,804,180
LESS:				
Total Depreciation and Amortization	706,308,821	133,833,304	206,851,776	365,623,741
Total Net Plant	867,111,799	67,940,232	313,991,127	485,180,439
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	22,452,891	7,115,250	5,477,227	9,860,414
Total Utility Plant	191,195,918	25,767,443	57,282,229	108,146,246
Total Other Property and Investments	6,515,146	-	-	6,515,146
Total Current and Accrued Assets	76,055,582	12,300,412	24,208,092	39,547,078
Total Deferred Debits	549,202,859	46,027,573	67,219,357	435,955,929
Total Assets and Other Debits	845,422,396	91,210,677	154,186,906	600,024,813
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	-	-	-	-
Total Deferred Credits	563,557,246	36,409,989	48,606,635	478,540,622
Total Liabilities and Other Credits	563,557,246	36,409,989	48,606,635	478,540,622
Total Rate Base	1,148,976,949	122,740,921	419,571,398	606,664,630
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$2,102,842,784
Interest for Year	133,253,386
Rate of Return	6.34%
(Interest/Long Term Debt)	

Table 7.3 NorthWestern 2003 for 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$346,909,408	$346,909,408	$0	$0
Total Transmission Expense	20,519,975	-	20,519,975	-
Total Distribution Expense	24,923,457	-	-	24,923,457
Total Customer and Sales Expenses	16,693,540	-	-	16,693,540
Total Administration and General Expenses	68,206,147	7,641,990	23,297,841	37,266,316
Total Operations and Maintenance	477,252,527	354,551,398	43,817,816	78,883,313
Total Depreciation and Amortization	59,400,601	6,182,738	17,718,884	35,498,979
Schedule 3A Items: Taxes				
Total Federal	63,296	6,224	23,134	33,938
Total State	72,332,324	7,205,942	18,613,798	46,512,584
Total County and Municipal	-	-	-	-
Total Taxes	72,395,620	7,212,166	18,636,932	46,546,522
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	119,372,911	119,372,911	-	-
Total Other Revenues	48,451,558	(1,232,657)	50,052,881	(368,666)
Total Other Included Items	167,824,469	118,140,254	50,052,881	(368,666)
Schedule 4: Average System Cost				
Total Operating Expenses	441,224,279	249,806,048	30,120,752	161,297,480
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	72,808,614	7,777,873	26,587,489	38,443,253
*(Total Rate Base * Rate of Return)*				
Total Cost	$514,032,893	$257,583,920	$56,708,241	$199,740,732
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$314,292,161
Total Retail Load (MWH)	6,370,664
Distribution Losses	318,533
Total Retail Load plus Distribution Losses	6,689,197
Average System Cost before NLSL Adjustment	**$46.99**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$46.99**
Contract System Costs	$314,292,161
Contract System Load	6,689,197
Average System Cost (See note below)	**$46.99**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.3.1 NorthWestern 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$2,238,806	$292,379	$739,066	$1,207,361
Total Production Plant	196,512,359	196,512,359	-	-
Total Transmission Plant	496,738,344	-	496,738,344	-
Total Distribution Plant	811,486,940	-	-	811,486,940
Total General Plant	66,444,171	4,968,799	23,365,493	38,109,879
Total Electric Plant In-Service	1,573,420,620	201,773,536	520,842,903	850,804,180
LESS:				
Total Depreciation and Amortization	706,308,821	133,833,304	206,851,776	365,623,741
Total Net Plant	867,111,799	67,940,232	313,991,127	485,180,439
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	22,452,891	7,115,250	5,477,227	9,860,414
Total Utility Plant	191,195,918	25,767,443	57,282,229	108,146,246
Total Other Property and Investments	6,515,146	-	-	6,515,146
Total Current and Accrued Assets	76,055,582	12,300,412	24,208,092	39,547,078
Total Deferred Debits	549,202,859	46,027,573	67,219,357	435,955,929
Total Assets and Other Debits	845,422,396	91,210,677	154,186,906	600,024,813
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	-	-	-	-
Total Deferred Credits	563,557,246	36,409,989	48,606,635	478,540,622
Total Liabilities and Other Credits	563,557,246	36,409,989	48,606,635	478,540,622
Total Rate Base	1,148,976,949	122,740,921	419,571,398	606,664,630
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$2,102,842,784
Interest for Year	133,253,386
Rate of Return	6.34%
(Interest/Long Term Debt)	

Table 7.3.1 NorthWestern 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$346,909,408	$346,909,408	$0	$0
Total Transmission Expense	20,519,975	-	20,519,975	-
Total Distribution Expense	24,923,457	-	-	24,923,457
Total Customer and Sales Expenses	16,693,540	-	-	16,693,540
Total Administration and General Expenses	68,206,147	7,641,990	23,297,841	37,266,316
Total Operations and Maintenance	477,252,527	354,551,398	43,817,816	78,883,313
Total Depreciation and Amortization	59,400,601	6,182,738	17,718,884	35,498,979
Schedule 3A Items: Taxes				
Total Federal	63,296	6,224	23,134	33,938
Total State	72,332,324	7,205,942	18,613,798	46,512,584
Total County and Municipal	-	-	-	-
Total Taxes	72,395,620	7,212,166	18,636,932	46,546,522
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	119,372,911	119,372,911	-	-
Total Other Revenues	48,451,558	(1,232,657)	50,052,881	(368,666)
Total Other Included Items	167,824,469	118,140,254	50,052,881	(368,666)
Schedule 4: Average System Cost				
Total Operating Expenses	441,224,279	249,806,048	30,120,752	161,297,480
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	72,808,614	7,777,873	26,587,489	38,443,253
*(Total Rate Base * Rate of Return)*				
Total Cost	$514,032,893	$257,583,920	$56,708,241	$199,740,732
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$314,292,161
Total Retail Load (MWH)	6,370,664
Distribution Losses	318,533
Total Retail Load plus Distribution Losses	6,689,197
Average System Cost before NLSL Adjustment	**$46.99**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$46.99**
Contract System Costs	$314,292,161
Contract System Load	6,689,197
Average System Cost (See note below)	**$46.99**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.3.2 NorthWestern 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$1,969,263	$254,736	$638,575	$1,075,951
Total Production Plant	201,632,867	201,632,867	-	-
Total Transmission Plant	505,455,120	-	505,455,120	-
Total Distribution Plant	851,654,070	-	-	851,654,070
Total General Plant	68,038,986	4,923,126	23,432,400	39,683,460
Total Electric Plant In-Service	1,628,750,306	206,810,729	529,526,095	892,413,481
LESS:				
Total Depreciation and Amortization	760,579,719	139,860,466	222,538,183	398,181,070
Total Net Plant	868,170,587	66,950,263	306,987,912	494,232,412
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	25,701,077	7,722,901	6,159,744	11,818,432
Total Utility Plant	192,595,825	26,158,266	57,786,917	108,650,642
Total Other Property and Investments	6,195,600	-	-	6,195,600
Total Current and Accrued Assets	46,961,065	8,485,040	14,330,390	24,145,635
Total Deferred Debits	539,471,197	19,203,673	52,719,117	467,548,407
Total Assets and Other Debits	810,924,764	61,569,880	130,996,169	618,358,716
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	-	-	-	-
Total Deferred Credits	606,342,708	26,473,346	36,750,832	543,118,530
Total Liabilities and Other Credits	606,342,708	26,473,346	36,750,832	543,118,530
Total Rate Base	1,072,752,643	102,046,797	401,233,248	569,472,598
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$787,306,000
Interest for Year	58,111,950
Rate of Return	7.38%
(Interest/Long Term Debt)	

Table 7.3.2 NorthWestern 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$349,084,818	$349,084,818	$0	$0
Total Transmission Expense	25,137,709	-	25,137,709	-
Total Distribution Expense	29,348,330	-	-	29,348,330
Total Customer and Sales Expenses	15,004,734	-	-	15,004,734
Total Administration and General Expenses	82,638,929	8,304,293	24,140,245	50,194,391
Total Operations and Maintenance	501,214,520	357,389,111	49,277,954	94,547,455
Total Depreciation and Amortization	61,631,919	6,891,467	18,098,305	36,642,147
Schedule 3A Items: Taxes				
Total Federal	4,098,337	361,037	1,297,260	2,440,040
Total State	81,529,807	7,854,789	20,114,900	53,560,118
Total County and Municipal	-	-	-	-
Total Taxes	85,628,144	8,215,826	21,412,160	56,000,158
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	114,608,124	114,608,124	-	-
Total Other Revenues	43,694,397	174,895	37,557,080	5,962,422
Total Other Included Items	158,302,521	114,783,019	37,557,080	5,962,422
Schedule 4: Average System Cost				
Total Operating Expenses	490,172,062	257,713,384	51,231,339	181,227,338
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	79,181,091	7,532,190	29,615,482	42,033,419
*(Total Rate Base * Rate of Return)*				
Total Cost	$569,353,153	$265,245,574	$80,846,821	$223,260,758
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$346,092,395
Total Retail Load (MWH)	6,535,574
Distribution Losses	326,779
Total Retail Load plus Distribution Losses	6,862,353
Average System Cost before NLSL Adjustment	**$50.43**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$50.43**
Contract System Costs	$346,092,395
Contract System Load	6,862,353
Average System Cost (See note below)	**$50.43**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.3.3 NorthWestern 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$1,215,477	$157,694	$389,943	$667,841
Total Production Plant	208,336,483	208,336,483	-	-
Total Transmission Plant	515,171,301	-	515,171,301	-
Total Distribution Plant	882,315,502	-	-	882,315,502
Total General Plant	68,697,621	4,974,556	23,410,903	40,312,162
Total Electric Plant In-Service	1,675,736,384	213,468,733	538,972,147	923,295,504
LESS:				
Total Depreciation and Amortization	811,706,385	145,496,688	238,266,386	427,943,310
Total Net Plant	864,029,999	67,972,044	300,705,761	495,352,194
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	21,537,355	6,358,951	5,222,850	9,955,554
Total Utility Plant	213,035,525	26,954,588	58,971,723	127,109,213
Total Other Property and Investments	10,587,179	8,741,253	-	1,845,926
Total Current and Accrued Assets	25,913,083	5,975,030	7,349,989	12,588,064
Total Deferred Debits	274,286,868	37,213,417	52,227,496	184,845,955
Total Assets and Other Debits	545,360,010	85,243,239	123,772,059	336,344,712
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	-	-	-	-
Total Deferred Credits	342,364,823	17,502,804	33,043,804	291,818,215
Total Liabilities and Other Credits	342,364,823	17,502,804	33,043,804	291,818,215
Total Rate Base	1,067,025,186	135,712,479	391,434,015	539,878,692
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$702,920,000
Interest for Year	46,013,854
Rate of Return	6.55%
(Interest/Long Term Debt)	

Table 7.3.3 NorthWestern 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$358,941,133	$358,941,133	$0	$0
Total Transmission Expense	26,668,287	-	26,668,287	-
Total Distribution Expense	30,932,422	-	-	30,932,422
Total Customer and Sales Expenses	14,858,770	-	-	14,858,770
Total Administration and General Expenses	54,273,437	5,305,682	15,114,514	33,853,241
Total Operations and Maintenance	485,674,049	364,246,815	41,782,801	79,644,433
Total Depreciation and Amortization	63,214,408	6,828,363	18,289,655	38,096,390
Schedule 3A Items: Taxes				
Total Federal	7,274,118	531,801	1,798,202	4,944,115
Total State	73,126,710	7,708,767	19,463,321	45,954,623
Total County and Municipal	-	-	-	-
Total Taxes	80,400,828	8,240,567	21,261,523	50,898,738
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	111,378,826	111,378,826	-	-
Total Other Revenues	46,403,356	237,281	40,054,262	6,111,813
Total Other Included Items	157,782,182	111,616,107	40,054,262	6,111,813
Schedule 4: Average System Cost				
Total Operating Expenses	471,507,103	267,699,637	41,279,717	162,527,749
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	69,848,548	8,883,876	25,623,666	35,341,005
*(Total Rate Base * Rate of Return)*				
Total Cost	$541,355,651	$276,583,514	$66,903,384	$197,868,754
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$343,486,897
Total Retail Load (MWH)	6,886,930
Distribution Losses	344,347
Total Retail Load plus Distribution Losses	7,231,277
Average System Cost before NLSL Adjustment	**$47.50**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$47.50**
Contract System Costs	$343,486,897
Contract System Load	7,231,277
Average System Cost (See note below)	**$47.50**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.3.4 NorthWestern 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$1,432,201	$181,705	$459,237	$791,259
Total Production Plant	215,145,621	215,145,621	-	-
Total Transmission Plant	543,752,964	-	543,752,964	-
Total Distribution Plant	936,878,605	-	-	936,878,605
Total General Plant	73,092,229	4,952,920	25,088,486	43,050,823
Total Electric Plant In-Service	1,770,301,620	220,280,246	569,300,687	980,720,687
LESS:				
Total Depreciation and Amortization	866,460,930	150,820,307	253,121,464	462,519,159
Total Net Plant	903,840,690	69,459,939	316,179,223	518,201,528
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	21,758,488	6,876,923	5,273,779	9,607,786
Total Utility Plant	191,536,571	26,862,721	60,041,346	104,632,504
Total Other Property and Investments	1,541,359	-	-	1,541,359
Total Current and Accrued Assets	31,180,910	6,849,468	8,935,574	15,395,867
Total Deferred Debits	242,978,137	25,202,463	64,561,811	153,213,863
Total Assets and Other Debits	488,995,465	65,791,575	138,812,511	284,391,379
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	4,331,833	4,331,833	-	-
Total Deferred Credits	312,008,691	18,373,461	33,080,525	260,554,704
Total Liabilities and Other Credits	316,340,524	22,705,294	33,080,525	260,554,704
Total Rate Base	1,076,495,631	112,546,220	421,911,208	542,038,203
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$671,920,000
Interest for Year	40,115,031
Rate of Return	5.97%
(Interest/Long Term Debt)	

Table 7.3.4 NorthWestern 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$385,715,321	$385,715,321	$0	$0
Total Transmission Expense	23,826,039	-	23,826,039	-
Total Distribution Expense	33,094,405	-	-	33,094,405
Total Customer and Sales Expenses	16,260,879	-	-	16,260,879
Total Administration and General Expenses	51,420,834	5,549,635	18,364,195	27,507,004
Total Operations and Maintenance	510,317,478	391,264,956	42,190,234	76,862,288
Total Depreciation and Amortization	64,629,508	7,348,854	18,289,622	38,991,032
Schedule 3A Items: Taxes				
Total Federal	6,913,975	710,729	2,704,067	3,499,179
Total State	81,783,720	8,549,601	22,095,915	51,138,205
Total County and Municipal	-	-	-	-
Total Taxes	88,697,695	9,260,330	24,799,981	54,637,384
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	105,792,580	105,792,580	-	-
Total Other Revenues	19,839,492	(3,576,393)	35,006,373	(11,590,487)
Total Other Included Items	125,632,072	102,216,187	35,006,373	(11,590,487)
Schedule 4: Average System Cost				
Total Operating Expenses	538,012,609	305,657,952	50,273,465	182,081,191
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	64,269,043	6,719,245	25,188,983	32,360,816
*(Total Rate Base * Rate of Return)*				
Total Cost	$602,281,652	$312,377,197	$75,462,448	$214,442,007
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$387,839,645
Total Retail Load (MWH)	7,019,031
Distribution Losses	350,952
Total Retail Load plus Distribution Losses	7,369,983
Average System Cost before NLSL Adjustment	**$52.62**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$52.62**
Contract System Costs	$387,839,645
Contract System Load	7,369,983
Average System Cost (See note below)	**$52.62**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4 PacifiCorp PNW Total 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$199,808,957	$88,261,898	$39,371,149	$72,175,910
Total Production Plant	2,181,939,478	2,181,939,478	-	-
Total Transmission Plant	1,015,395,292	-	1,015,395,292	-
Total Distribution Plant	1,739,593,813	-	-	1,739,593,813
Total General Plant	467,146,389	238,352,600	76,880,367	151,913,422
Total Electric Plant In-Service	5,603,883,930	2,508,553,976	1,131,646,808	1,963,683,145
LESS:				
Total Depreciation and Amortization	2,475,859,030	1,264,060,947	435,901,999	775,896,083
Total Net Plant	3,128,024,900	1,244,493,029	695,744,809	1,187,787,062
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	50,919,850	24,878,625	7,294,820	18,746,405
Total Utility Plant	230,351,989	79,395,979	2,928,181	148,027,829
Total Other Property and Investments	36,650,803	-	-	36,650,803
Total Current and Accrued Assets	166,145,088	138,641,646	10,178,037	17,325,404
Total Deferred Debits	761,359,445	428,294,660	12,112,309	320,952,476
Total Assets and Other Debits	1,245,427,174	671,210,909	32,513,348	541,702,917
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	314,239,201	314,239,201	-	-
Total Deferred Credits	685,594,075	37,918,126	12,210,015	635,465,933
Total Liabilities and Other Credits	999,833,276	352,157,327	12,210,015	635,465,933
Total Rate Base	3,373,618,798	1,563,546,611	716,048,142	1,094,024,045
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,895,711,464
Interest for Year	252,443,726
Rate of Return	6.48%
(Interest/Long Term Debt)	

Table 7.4 PacifiCorp PNW Total 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$863,595,501	$860,587,371	$0	$3,008,130
Total Transmission Expense	44,289,778	-	44,289,778	-
Total Distribution Expense	55,428,862	-	-	55,428,862
Total Customer and Sales Expenses	41,757,479	-	-	41,757,479
Total Administration and General Expenses	117,755,317	53,909,766	14,068,785	49,776,766
Total Operations and Maintenance	1,122,826,937	914,497,136	58,358,563	149,971,237
Total Depreciation and Amortization	192,702,907	81,366,345	27,926,119	83,410,443
Schedule 3A Items: Taxes				
Total Federal	63,581,811	7,455,729	1,343,652	54,782,431
Total State	63,990,559	15,208,353	5,266,815	43,515,392
Total County and Municipal	266,104	-	-	266,104
Total Taxes	127,838,475	22,664,082	6,610,466	98,563,927
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(241,291)	(108,174)	(49,401)	(83,716)
Total Sales from Resale	425,514,527	425,514,527	-	-
Total Other Revenues	61,434,353	11,730,616	31,456,962	18,246,775
Total Other Included Items	486,707,588	437,136,969	31,407,561	18,163,058
Schedule 4: Average System Cost				
Total Operating Expenses	956,660,731	581,390,594	61,487,588	313,782,549
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	218,611,904	101,318,472	46,400,218	70,893,214
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,175,272,634	$682,709,065	$107,887,806	$384,675,763
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$790,596,871
Total Retail Load (MWH)	20,141,374
Distribution Losses	1,007,069
Total Retail Load plus Distribution Losses	21,148,443
Average System Cost before NLSL Adjustment	**$37.38**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$37.38**
Contract System Costs	$790,596,871
Contract System Load	21,148,443
Average System Cost (See note below)	**$37.38**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4 PacifiCorp PNW Total 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$223,270,968	$98,073,453	$43,730,611	$81,466,904
Total Production Plant	2,241,715,145	2,241,715,145	-	-
Total Transmission Plant	1,020,347,319	-	1,020,347,319	-
Total Distribution Plant	1,821,207,560	-	-	1,821,207,560
Total General Plant	483,635,701	247,651,223	78,330,930	157,653,548
Total Electric Plant In-Service	5,790,176,695	2,587,439,821	1,142,408,861	2,060,328,012
LESS:				
Total Depreciation and Amortization	2,528,081,004	1,269,337,185	434,393,021	824,350,798
Total Net Plant	3,262,095,691	1,318,102,637	708,015,839	1,235,977,215
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	53,599,145	25,913,828	7,315,676	20,369,641
Total Utility Plant	228,073,642	75,096,882	2,838,751	150,138,009
Total Other Property and Investments	36,811,082	-	-	36,811,082
Total Current and Accrued Assets	181,203,463	152,956,729	10,240,130	18,006,603
Total Deferred Debits	815,961,000	434,101,717	26,643,326	355,215,958
Total Assets and Other Debits	1,315,648,332	688,069,156	47,037,884	580,541,292
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	331,932,866	331,932,866	-	-
Total Deferred Credits	706,171,037	56,609,931	3,954,523	645,606,583
Total Liabilities and Other Credits	1,038,103,902	388,542,796	3,954,523	645,606,583
Total Rate Base	3,539,640,120	1,617,628,997	751,099,200	1,170,911,924
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,820,085,702
Interest for Year	220,390,393
Rate of Return	5.77%
(Interest/Long Term Debt)	

Table 7.4 PacifiCorp PNW Total 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$889,424,877	$884,180,975	$0	$5,243,903
Total Transmission Expense	45,777,023	-	45,777,023	-
Total Distribution Expense	61,412,368	-	-	61,412,368
Total Customer and Sales Expenses	48,676,133	-	-	48,676,133
Total Administration and General Expenses	110,887,376	50,514,270	12,748,385	47,624,721
Total Operations and Maintenance	1,156,177,778	934,695,244	58,525,408	162,957,125
Total Depreciation and Amortization	188,733,856	86,688,526	29,240,824	72,804,507
Schedule 3A Items: Taxes				
Total Federal	60,770,638	7,657,393	1,336,004	51,777,241
Total State	66,893,226	15,326,477	5,255,496	46,311,253
Total County and Municipal	277,289	-	-	277,289
Total Taxes	127,941,154	22,983,870	6,591,501	98,365,783
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales from Resale	442,670,340	442,670,340	-	-
Total Other Revenues	48,695,447	6,580,225	27,421,214	14,694,009
Total Other Included Items	491,365,787	449,250,565	27,421,214	14,694,009
Schedule 4: Average System Cost				
Total Operating Expenses	981,487,001	595,117,076	66,936,519	319,433,407
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	204,210,779	93,325,103	43,332,810	67,552,866
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,185,697,780	$688,442,178	$110,269,329	$386,986,273
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$798,711,507
Total Retail Load (MWH)	20,652,184
Distribution Losses	1,032,609
Total Retail Load plus Distribution Losses	21,684,793
Average System Cost before NLSL Adjustment	**$36.83**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$36.83**
Contract System Costs	$798,711,507
Contract System Load	21,684,793
Average System Cost (See note below)	**$36.83**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4 PacifiCorp PNW Total 2004 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$259,241,138	$111,676,620	$52,149,682	$95,414,835
Total Production Plant	2,269,291,844	2,269,291,844	-	-
Total Transmission Plant	1,067,021,553	-	1,067,021,553	-
Total Distribution Plant	1,906,735,119	-	-	1,906,735,119
Total General Plant	503,961,072	255,102,116	81,800,024	167,058,933
Total Electric Plant In-Service	6,006,250,726	2,636,070,580	1,200,971,259	2,169,208,887
LESS:				
Total Depreciation and Amortization	2,622,658,774	1,301,783,246	450,801,485	870,074,043
Total Net Plant	3,383,591,951	1,334,287,334	750,169,773	1,299,134,845
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	59,664,431	26,457,770	7,313,800	25,892,861
Total Utility Plant	270,737,740	74,007,689	2,844,221	193,885,830
Total Other Property and Investments	143,720,716	105,963,419	-	37,757,297
Total Current and Accrued Assets	149,169,320	105,673,179	15,648,186	27,847,955
Total Deferred Debits	957,852,955	255,134,249	27,042,594	675,676,112
Total Assets and Other Debits	1,581,145,161	567,236,306	52,848,800	961,060,055
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	236,991,470	236,991,470	-	-
Total Current and Accrued Liabilities	36,956,851	36,956,851	-	-
Total Deferred Credits	974,182,379	45,245,086	4,775,503	924,161,790
Total Liabilities and Other Credits	1,248,130,699	319,193,406	4,775,503	924,161,790
Total Rate Base	3,716,606,414	1,582,330,233	798,243,071	1,336,033,110
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,933,071,649
Interest for Year	229,563,698
Rate of Return	5.84%
(Interest/Long Term Debt)	

Table 7.4 PacifiCorp PNW Total 2004 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$665,009,163	$657,895,342	$0	$7,113,821
Total Transmission Expense	45,053,465	-	45,053,465	-
Total Distribution Expense	95,048,552	-	-	95,048,552
Total Customer and Sales Expenses	55,779,649	-	-	55,779,649
Total Administration and General Expenses	108,773,012	46,115,211	13,456,936	49,200,866
Total Operations and Maintenance	969,663,842	704,010,553	58,510,401	207,142,888
Total Depreciation and Amortization	188,704,941	87,286,134	30,219,832	71,198,975
Schedule 3A Items: Taxes				
Total Federal	45,246,377	106,001	19,760	45,120,616
Total State	86,057,990	12,887,061	4,380,554	68,790,375
Total County and Municipal	104,267	-	-	104,267
Total Taxes	131,408,635	12,993,063	4,400,314	114,015,258
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales from Resale	141,779,372	141,779,372	-	-
Total Other Revenues	68,149,348	15,744,278	30,042,778	22,362,292
Total Other Included Items	209,928,721	157,523,651	30,042,778	22,362,292
Schedule 4: Average System Cost				
Total Operating Expenses	1,079,848,697	646,766,099	63,087,768	369,994,829
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	216,929,156	92,356,716	46,591,481	77,980,960
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,296,777,852	$739,122,815	$109,679,249	$447,975,789
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$848,802,064
Total Retail Load (MWH)	20,456,769
Distribution Losses	1,022,838
Total Retail Load plus Distribution Losses	21,479,607
Average System Cost before NLSL Adjustment	**$39.52**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$39.52**
Contract System Costs	$848,802,064
Contract System Load	21,479,607
Average System Cost (See note below)	**$39.52**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4 PacifiCorp PNW Total 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$293,614,146	$127,335,919	$59,399,730	$106,878,497
Total Production Plant	2,370,939,852	2,370,939,852	-	-
Total Transmission Plant	1,105,899,303	-	1,105,899,303	-
Total Distribution Plant	1,991,439,550	-	-	1,991,439,550
Total General Plant	517,952,765	246,868,433	91,331,390	179,752,942
Total Electric Plant In-Service	6,279,845,616	2,745,144,204	1,256,630,423	2,278,070,989
LESS:				
Total Depreciation and Amortization	2,732,522,562	1,360,518,147	527,577,636	844,426,779
Total Net Plant	3,547,323,054	1,384,626,057	729,052,787	1,433,644,210
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	59,669,779	26,707,285	7,634,249	25,328,245
Total Utility Plant	354,176,510	81,415,485	6,269,245	266,491,779
Total Other Property and Investments	256,142,257	216,533,587	-	39,608,670
Total Current and Accrued Assets	250,980,365	214,981,057	12,903,215	23,096,093
Total Deferred Debits	665,882,824	295,891,920	17,985,255	352,005,648
Total Assets and Other Debits	1,586,851,734	835,529,334	44,791,964	706,530,436
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	228,651,190	228,651,190	-	-
Total Current and Accrued Liabilities	90,144,247	90,144,247	-	-
Total Deferred Credits	1,039,608,627	72,369,361	3,779,778	963,459,488
Total Liabilities and Other Credits	1,358,404,063	391,164,797	3,779,778	963,459,488
Total Rate Base	3,775,770,725	1,828,990,594	770,064,972	1,176,715,159
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,052,276,242
Interest for Year	237,603,134
Rate of Return	5.86%
(Interest/Long Term Debt)	

Table 7.4 PacifiCorp PNW Total 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$810,401,726	$803,206,604	$0	$7,195,122
Total Transmission Expense	49,299,105	-	49,299,105	-
Total Distribution Expense	84,610,710	-	-	84,610,710
Total Customer and Sales Expenses	62,437,533	-	-	62,437,533
Total Administration and General Expenses	105,137,913	44,980,427	11,774,887	48,382,599
Total Operations and Maintenance	1,111,886,987	848,187,032	61,073,992	202,625,963
Total Depreciation and Amortization	188,032,601	87,487,535	30,177,194	70,367,872
Schedule 3A Items: Taxes				
Total Federal	56,482,443	6,533,400	1,228,017	48,721,025
Total State	62,628,127	12,893,916	4,399,240	45,334,970
Total County and Municipal	142,923	-	-	142,923
Total Taxes	119,253,492	19,427,317	5,627,257	94,198,918
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(25,776)	(11,294)	(5,175)	(9,306)
Total Sales from Resale	266,309,277	266,309,277	-	-
Total Other Revenues	80,465,050	15,937,643	37,337,772	27,189,635
Total Other Included Items	346,748,551	282,235,625	37,332,596	27,180,329
Schedule 4: Average System Cost				
Total Operating Expenses	1,072,424,529	672,866,258	59,545,847	340,012,424
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	221,390,375	107,241,923	45,152,364	68,996,088
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,293,814,904	$780,108,181	$104,698,211	$409,008,512
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$884,806,392
Total Retail Load (MWH)	20,672,447
Distribution Losses	1,033,622
Total Retail Load plus Distribution Losses	21,706,069
Average System Cost before NLSL Adjustment	**$40.76**
New Large Single Load(s) (MWH)	124,942.00
Cost of Serving New Large Single Load(s)	$5,093,022
Average System Cost after NLSL Adjustment	**$40.76**
Contract System Costs	$879,713,370
Contract System Load	21,581,127
Average System Cost (See note below)	**$40.76**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4 PacifiCorp PNW Total 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$296,605,932	$134,048,852	$57,136,235	$105,420,845
Total Production Plant	2,650,046,497	2,650,046,497	-	-
Total Transmission Plant	1,129,521,628	-	1,129,521,628	-
Total Distribution Plant	2,083,832,343	-	-	2,083,832,343
Total General Plant	520,819,927	250,631,674	90,377,943	179,810,310
Total Electric Plant In-Service	6,680,826,328	3,034,727,023	1,277,035,806	2,369,063,499
LESS:				
Total Depreciation and Amortization	2,853,485,653	1,420,464,261	549,690,207	883,331,186
Total Net Plant	3,827,340,674	1,614,262,762	727,345,599	1,485,732,313
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	64,449,466	28,397,291	8,826,151	27,226,025
Total Utility Plant	415,765,790	85,585,571	7,527,252	322,652,967
Total Other Property and Investments	139,078,276	98,686,953	-	40,391,323
Total Current and Accrued Assets	188,698,655	139,029,563	17,536,166	32,132,926
Total Deferred Debits	998,159,036	251,242,170	43,949,307	702,967,559
Total Assets and Other Debits	1,806,151,223	602,941,548	77,838,876	1,125,370,799
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	211,934,075	211,934,075	-	-
Total Current and Accrued Liabilities	46,012,070	46,012,070	-	-
Total Deferred Credits	1,099,108,571	47,878,342	5,774,125	1,045,456,104
Total Liabilities and Other Credits	1,357,054,716	305,824,486	5,774,125	1,045,456,104
Total Rate Base	4,276,437,182	1,911,379,824	799,410,350	1,565,647,008
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,086,372,000
Interest for Year	245,313,780
Rate of Return	6.00%
(Interest/Long Term Debt)	

Table 7.4 PacifiCorp PNW Total 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$865,224,138	$857,518,853	$0	$7,705,285
Total Transmission Expense	59,121,451	-	59,121,451	-
Total Distribution Expense	91,238,454	-	-	91,238,454
Total Customer and Sales Expenses	70,893,100	-	-	70,893,100
Total Administration and General Expenses	104,501,703	45,042,586	11,487,758	47,971,359
Total Operations and Maintenance	1,190,978,846	902,561,439	70,609,209	217,808,197
Total Depreciation and Amortization	195,823,094	93,002,005	30,785,178	72,035,911
Schedule 3A Items: Taxes				
Total Federal	96,263,734	6,639,684	1,275,576	88,348,474
Total State	76,612,696	15,980,575	5,281,612	55,350,509
Total County and Municipal	575,095	-	-	575,095
Total Taxes	173,451,525	22,620,258	6,557,189	144,274,078
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales from Resale	324,212,511	324,212,511	-	-
Total Other Revenues	63,720,480	14,639,739	26,881,866	22,198,874
Total Other Included Items	387,932,991	338,852,251	26,881,866	22,198,874
Schedule 4: Average System Cost				
Total Operating Expenses	1,172,320,473	679,331,452	81,069,710	411,919,312
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	256,723,805	114,744,279	47,990,338	93,989,188
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,429,044,279	$794,075,731	$129,060,048	$505,908,500
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$923,135,779
Total Retail Load (MWH)	21,409,637
Distribution Losses	1,070,482
Total Retail Load plus Distribution Losses	22,480,119
Average System Cost before NLSL Adjustment	**$41.06**
New Large Single Load(s) (MWH)	342,068.00
Cost of Serving New Large Single Load(s)	$14,046,866
Average System Cost after NLSL Adjustment	**$41.06**
Contract System Costs	$909,088,914
Contract System Load	22,138,051
Average System Cost (See note below)	**$41.06**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4A PacifiCorp - Idaho 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$9,922,090	$4,358,833	$2,814,068	$2,749,189
Total Production Plant	304,546,370	304,546,370	-	-
Total Transmission Plant	196,615,544	-	196,615,544	-
Total Distribution Plant	192,082,500	-	-	192,082,500
Total General Plant	61,720,977	34,021,905	11,506,408	16,192,664
Total Electric Plant In-Service	764,887,481	342,927,108	210,936,020	211,024,353
LESS:				
Total Depreciation and Amortization	413,366,756	235,877,364	82,000,361	95,489,031
Total Net Plant	351,520,725	107,049,744	128,935,659	115,535,323
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	6,307,357	3,382,231	1,094,381	1,830,745
Total Utility Plant	43,151,507	14,537,785	486,775	28,126,947
Total Other Property and Investments	6,486,851	-	-	6,486,851
Total Current and Accrued Assets	26,520,685	22,365,624	2,101,759	2,053,302
Total Deferred Debits	117,690,032	66,223,301	2,408,120	49,058,611
Total Assets and Other Debits	200,156,431	106,508,941	6,091,035	87,556,456
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	51,384,891	51,384,891	-	-
Total Deferred Credits	117,400,097	4,543,635	1,627,574	111,228,888
Total Liabilities and Other Credits	168,784,988	55,928,526	1,627,574	111,228,888
Total Rate Base	382,892,168	157,630,159	133,399,119	91,862,890
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,895,711,464
Interest for Year	252,443,726
Rate of Return	6.48%
(Interest/Long Term Debt)	

Table 7.4A PacifiCorp - Idaho 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$124,453,126	$124,453,126	$0	$0
Total Transmission Expense	6,357,198	-	6,357,198	-
Total Distribution Expense	4,926,322	-	-	4,926,322
Total Customer and Sales Expenses	3,635,457	-	-	3,635,457
Total Administration and General Expenses	15,640,887	7,158,857	2,397,852	6,084,178
Total Operations and Maintenance	155,012,990	131,611,984	8,755,050	14,645,957
Total Depreciation and Amortization	23,838,233	11,338,232	4,131,956	8,368,044
Schedule 3A Items: Taxes				
Total Federal	6,792,889	988,867	221,038	5,582,985
Total State	4,520,965	1,932,739	908,099	1,680,128
Total County and Municipal	43,514	-	-	43,514
Total Taxes	11,357,368	2,921,605	1,129,136	7,306,627
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(39,456)	(17,690)	(10,881)	(10,886)
Total Sales for Resale	59,245,804	59,245,804	-	-
Total Other Revenues	8,977,677	1,918,310	5,003,574	2,055,792
Total Other Included Items	68,184,025	61,146,425	4,992,693	2,044,907
Schedule 4: Average System Cost				
Total Operating Expenses	122,024,567	84,725,397	9,023,449	28,275,721
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	24,811,572	10,214,500	8,644,319	5,952,754
*(Total Rate Base * Rate of Return)*				
Total Cost	$146,836,139	$94,939,897	$17,667,768	$34,228,474
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$112,607,664
Total Retail Load (MWH)	3,219,006
Distribution Losses	160,950
Total Retail Load plus Distribution Losses	3,379,956
Average System Cost before NLSL Adjustment	**$33.32**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$33.32**
Contract System Costs	$112,607,664
Contract System Load	3,379,956
Average System Cost (See note below)	**$33.32**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4A PacifiCorp - Idaho 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$11,152,657	$5,062,859	$2,761,503	$3,328,295
Total Production Plant	305,895,741	305,895,741	-	-
Total Transmission Plant	166,848,806	-	166,848,806	-
Total Distribution Plant	201,094,129	-	-	201,094,129
Total General Plant	63,736,170	35,770,977	10,558,889	17,406,304
Total Electric Plant In-Service	748,727,503	346,729,577	180,169,198	221,828,727
LESS:				
Total Depreciation and Amortization	344,905,940	181,656,199	61,506,241	101,743,500
Total Net Plant	403,821,562	165,073,378	118,662,957	120,085,227
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	6,361,481	3,368,703	1,062,682	1,930,097
Total Utility Plant	34,965,872	10,347,893	418,672	24,199,307
Total Other Property and Investments	4,770,908	-	-	4,770,908
Total Current and Accrued Assets	29,236,274	24,933,130	1,951,320	2,351,824
Total Deferred Debits	118,680,767	62,198,252	3,768,011	52,714,505
Total Assets and Other Debits	194,015,303	100,847,978	7,200,685	85,966,641
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	54,278,187	54,278,187	-	-
Total Deferred Credits	121,583,611	8,168,732	489,073	112,925,806
Total Liabilities and Other Credits	175,861,797	62,446,919	489,073	112,925,806
Total Rate Base	421,975,068	203,474,436	125,374,569	93,126,063
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,820,085,702
Interest for Year	220,390,393
Rate of Return	5.77%
(Interest/Long Term Debt)	

Table 7.4A PacifiCorp - Idaho 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$126,508,465	$126,508,465	$0	$0
Total Transmission Expense	6,586,686	-	6,586,686	-
Total Distribution Expense	5,211,059	-	-	5,211,059
Total Customer and Sales Expenses	4,237,803	-	-	4,237,803
Total Administration and General Expenses	14,728,651	6,821,969	1,914,767	5,991,915
Total Operations and Maintenance	157,272,664	133,330,434	8,501,453	15,440,777
Total Depreciation and Amortization	23,712,846	12,129,629	4,187,150	7,396,067
Schedule 3A Items: Taxes				
Total Federal	6,526,897	1,023,249	199,698	5,303,950
Total State	5,116,957	1,979,563	794,971	2,342,423
Total County and Municipal	45,343	-	-	45,343
Total Taxes	11,689,197	3,002,812	994,669	7,691,715
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	61,634,465	61,634,465	-	-
Total Other Revenues	6,946,597	1,111,871	4,148,114	1,686,612
Total Other Included Items	68,581,063	62,746,336	4,148,114	1,686,612
Schedule 4: Average System Cost				
Total Operating Expenses	124,093,645	85,716,539	9,535,158	28,841,948
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	24,344,808	11,738,954	7,233,176	5,372,678
*(Total Rate Base * Rate of Return)*				
Total Cost	$148,438,452	$97,455,493	$16,768,333	$34,214,625
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$114,223,827
Total Retail Load (MWH)	3,280,221
Distribution Losses	164,011
Total Retail Load plus Distribution Losses	3,444,232
Average System Cost before NLSL Adjustment	**$33.16**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$33.16**
Contract System Costs	$114,223,827
Contract System Load	3,444,232
Average System Cost (See note below)	**$33.16**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4A PacifiCorp - Idaho 2004 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$17,307,185	$7,895,173	$4,048,679	$5,363,333
Total Production Plant	309,925,439	309,925,439	-	-
Total Transmission Plant	158,931,091	-	158,931,091	-
Total Distribution Plant	210,537,912	-	-	210,537,912
Total General Plant	64,830,215	35,218,596	10,344,704	19,266,915
Total Electric Plant In-Service	761,531,842	353,039,209	173,324,474	235,168,160
LESS:				
Total Depreciation and Amortization	357,408,756	185,638,257	63,721,043	108,049,456
Total Net Plant	404,123,086	167,400,952	109,603,431	127,118,704
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	6,761,201	3,356,511	1,040,772	2,363,918
Total Utility Plant	39,265,096	10,259,056	388,247	28,617,793
Total Other Property and Investments	20,419,209	15,783,076	-	4,636,134
Total Current and Accrued Assets	21,391,770	15,624,881	2,480,690	3,286,199
Total Deferred Debits	136,185,178	37,490,629	3,556,705	95,137,845
Total Assets and Other Debits	224,022,455	82,514,153	7,466,414	134,041,888
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	35,299,486	35,299,486	-	-
Total Current and Accrued Liabilities	5,504,662	5,504,662	-	-
Total Deferred Credits	191,337,017	5,929,946	625,369	184,781,702
Total Liabilities and Other Credits	232,141,165	46,734,094	625,369	184,781,702
Total Rate Base	396,004,376	203,181,011	116,444,475	76,378,890
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,933,071,649
Interest for Year	229,563,698
Rate of Return	5.84%
(Interest/Long Term Debt)	

Table 7.4A PacifiCorp - Idaho 2004 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$91,625,849	$91,625,849	$0	$0
Total Transmission Expense	6,457,278	-	6,457,278	-
Total Distribution Expense	8,271,232	-	-	8,271,232
Total Customer and Sales Expenses	4,711,290	-	-	4,711,290
Total Administration and General Expenses	13,822,512	6,024,792	1,868,901	5,928,820
Total Operations and Maintenance	124,888,160	97,650,640	8,326,178	18,911,342
Total Depreciation and Amortization	23,830,676	12,255,480	4,264,033	7,311,162
Schedule 3A Items: Taxes				
Total Federal	3,750,515	13,631	2,720	3,734,165
Total State	4,911,124	1,970,677	762,985	2,177,463
Total County and Municipal	15,530	-	-	15,530
Total Taxes	8,677,170	1,984,308	765,705	5,927,158
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	19,824,907	19,824,907	-	-
Total Other Revenues	9,579,482	2,470,951	4,505,370	2,603,161
Total Other Included Items	29,404,389	22,295,858	4,505,370	2,603,161
Schedule 4: Average System Cost				
Total Operating Expenses	127,991,618	89,594,571	8,850,547	29,546,500
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	23,113,799	11,859,175	6,796,577	4,458,048
*(Total Rate Base * Rate of Return)*				
Total Cost	$151,105,417	$101,453,745	$15,647,124	$34,004,548
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$117,100,869
Total Retail Load (MWH)	3,262,418
Distribution Losses	163,121
Total Retail Load plus Distribution Losses	3,425,539
Average System Cost before NLSL Adjustment	**$34.18**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$34.18**
Contract System Costs	$117,100,869
Contract System Load	3,425,539
Average System Cost (See note below)	**$34.18**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4A PacifiCorp - Idaho 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$39,994,460	$18,856,346	$9,053,029	$12,085,085
Total Production Plant	343,095,400	343,095,400	-	-
Total Transmission Plant	164,721,867	-	164,721,867	-
Total Distribution Plant	219,890,807	-	-	219,890,807
Total General Plant	73,729,090	36,367,632	15,028,696	22,332,762
Total Electric Plant In-Service	841,431,625	398,319,378	188,803,592	254,308,655
LESS:				
Total Depreciation and Amortization	378,560,188	191,109,449	62,803,537	124,647,203
Total Net Plant	462,871,437	207,209,930	126,000,055	129,661,452
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	6,828,963	3,396,105	1,088,175	2,344,683
Total Utility Plant	51,079,819	11,194,633	812,666	39,072,520
Total Other Property and Investments	37,115,778	32,252,319	-	4,863,460
Total Current and Accrued Assets	37,041,741	32,211,865	2,068,539	2,761,337
Total Deferred Debits	121,244,231	53,885,825	2,238,644	65,119,761
Total Assets and Other Debits	253,310,532	132,940,747	6,208,023	114,161,762
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	34,057,216	34,057,216	-	-
Total Current and Accrued Liabilities	13,426,836	13,426,836	-	-
Total Deferred Credits	199,552,573	10,348,561	469,089	188,734,924
Total Liabilities and Other Credits	247,036,625	57,832,613	469,089	188,734,924
Total Rate Base	469,145,343	282,318,064	131,738,989	55,088,290
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,052,276,242
Interest for Year	237,603,134
Rate of Return	5.86%
(Interest/Long Term Debt)	

Table 7.4A PacifiCorp - Idaho 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$112,006,082	$112,006,082	$0	$0
Total Transmission Expense	7,070,604	-	7,070,604	-
Total Distribution Expense	7,688,329	-	-	7,688,329
Total Customer and Sales Expenses	5,273,632	-	-	5,273,632
Total Administration and General Expenses	13,360,576	5,930,281	1,634,792	5,795,503
Total Operations and Maintenance	145,399,224	117,936,363	8,705,396	18,757,464
Total Depreciation and Amortization	23,991,017	12,235,548	4,294,393	7,461,076
Schedule 3A Items: Taxes				
Total Federal	5,371,737	846,274	166,255	4,359,208
Total State	4,588,073	618,755	97,810	3,871,508
Total County and Municipal	21,288	-	-	21,288
Total Taxes	9,981,098	1,465,028	264,066	8,252,004
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(3,839)	(1,817)	(861)	(1,160)
Total Sales for Resale	37,237,833	37,237,833	-	-
Total Other Revenues	11,559,194	2,564,593	5,582,660	3,411,941
Total Other Included Items	48,793,188	39,800,608	5,581,799	3,410,781
Schedule 4: Average System Cost				
Total Operating Expenses	130,578,151	91,836,331	7,682,056	31,059,764
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	27,508,096	16,553,575	7,724,448	3,230,074
*(Total Rate Base * Rate of Return)*				
Total Cost	$158,086,247	$108,389,906	$15,406,504	$34,289,837
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$123,796,410
Total Retail Load (MWH)	3,221,358
Distribution Losses	161,068
Total Retail Load plus Distribution Losses	3,382,426
Average System Cost before NLSL Adjustment	**$36.60**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$36.60**
Contract System Costs	$123,796,410
Contract System Load	3,382,426
Average System Cost (See note below)	**$36.60**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4A PacifiCorp - Idaho 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$40,264,263	$19,570,554	$8,996,572	$11,697,137
Total Production Plant	384,969,462	384,969,462	-	-
Total Transmission Plant	176,970,232	-	176,970,232	-
Total Distribution Plant	230,092,636	-	-	230,092,636
Total General Plant	75,185,101	37,601,439	15,467,668	22,115,994
Total Electric Plant In-Service	907,481,695	442,141,455	201,434,472	263,905,767
LESS:				
Total Depreciation and Amortization	403,509,073	207,663,431	65,555,004	130,290,638
Total Net Plant	503,972,622	234,478,024	135,879,468	133,615,130
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	7,653,427	3,777,338	1,294,924	2,581,165
Total Utility Plant	62,806,744	12,126,794	1,017,521	49,662,429
Total Other Property and Investments	20,829,793	15,461,991	-	5,367,802
Total Current and Accrued Assets	28,702,536	21,837,920	2,984,386	3,880,230
Total Deferred Debits	150,260,883	39,179,874	6,084,451	104,996,558
Total Assets and Other Debits	270,253,382	92,383,917	11,381,282	166,488,183
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	33,205,227	33,205,227	-	-
Total Current and Accrued Liabilities	7,209,040	7,209,040	-	-
Total Deferred Credits	176,551,299	11,569,995	906,470	164,074,835
Total Liabilities and Other Credits	216,965,567	51,984,262	906,470	164,074,835
Total Rate Base	557,260,437	274,877,679	146,354,281	136,028,478
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,086,372,000
Interest for Year	245,313,780
Rate of Return	6.00%
(Interest/Long Term Debt)	

Table 7.4A PacifiCorp - Idaho 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$125,366,788	$125,366,788	$0	$0
Total Transmission Expense	8,635,451	-	8,635,451	-
Total Distribution Expense	8,118,293	-	-	8,118,293
Total Customer and Sales Expenses	6,479,692	-	-	6,479,692
Total Administration and General Expenses	14,016,768	6,241,491	1,723,944	6,051,333
Total Operations and Maintenance	162,616,992	131,608,279	10,359,395	20,649,318
Total Depreciation and Amortization	25,628,934	13,465,887	4,558,761	7,604,287
Schedule 3A Items: Taxes				
Total Federal	15,041,245	906,203	185,209	13,949,832
Total State	5,872,106	2,037,083	726,705	3,108,318
Total County and Municipal	90,104	-	-	90,104
Total Taxes	21,003,455	2,943,287	911,914	17,148,254
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	47,355,422	47,355,422	-	-
Total Other Revenues	9,565,413	2,453,606	4,273,925	2,837,882
Total Other Included Items	56,920,835	49,809,027	4,273,925	2,837,882
Schedule 4: Average System Cost				
Total Operating Expenses	152,328,547	98,208,425	11,556,145	42,563,976
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	33,453,554	16,501,504	8,785,965	8,166,085
*(Total Rate Base * Rate of Return)*				
Total Cost	$185,782,100	$114,709,929	$20,342,110	$50,730,061
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$135,052,039
Total Retail Load (MWH)	3,331,580
Distribution Losses	166,579
Total Retail Load plus Distribution Losses	3,498,159
Average System Cost before NLSL Adjustment	**$38.61**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$38.61**
Contract System Costs	$135,052,039
Contract System Load	3,498,159
Average System Cost (See note below)	**$38.61**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4B PacifiCorp - Oregon 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$151,706,853	$66,020,542	$28,416,651	$57,269,660
Total Production Plant	1,445,477,084	1,445,477,084	-	-
Total Transmission Plant	622,164,204	-	622,164,204	-
Total Distribution Plant	1,253,882,187	-	-	1,253,882,187
Total General Plant	314,881,803	156,161,018	49,457,130	109,263,655
Total Electric Plant In-Service	3,788,112,132	1,667,658,644	700,037,986	1,420,415,503
LESS:				
Total Depreciation and Amortization	1,611,603,577	787,769,931	271,025,835	552,807,812
Total Net Plant	2,176,508,555	879,888,713	429,012,151	867,607,691
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	35,506,323	16,756,648	4,753,593	13,996,082
Total Utility Plant	144,237,278	50,358,714	2,115,617	91,762,947
Total Other Property and Investments	23,677,101	-	-	23,677,101
Total Current and Accrued Assets	107,123,790	88,574,000	6,151,775	12,398,015
Total Deferred Debits	534,037,151	301,814,608	7,452,109	224,770,434
Total Assets and Other Debits	844,581,643	457,503,970	20,473,094	366,604,580
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	199,734,475	199,734,475	-	-
Total Deferred Credits	448,938,597	26,364,131	8,272,182	414,302,284
Total Liabilities and Other Credits	648,673,071	226,098,606	8,272,182	414,302,284
Total Rate Base	2,372,417,127	1,111,294,077	441,213,064	819,909,986
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,895,711,464
Interest for Year	252,443,726
Rate of Return	6.48%
(Interest/Long Term Debt)	

Table 7.4B PacifiCorp - Oregon 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$568,198,316	$565,190,186	$0	$3,008,130
Total Transmission Expense	29,104,639	-	29,104,639	-
Total Distribution Expense	43,379,292	-	-	43,379,292
Total Customer and Sales Expenses	30,869,697	-	-	30,869,697
Total Administration and General Expenses	79,977,229	36,341,582	8,924,108	34,711,539
Total Operations and Maintenance	751,529,173	601,531,768	38,028,747	111,968,658
Total Depreciation and Amortization	133,481,609	53,790,479	18,220,281	61,470,850
Schedule 3A Items: Taxes				
Total Federal	44,801,533	5,045,010	863,706	38,892,817
Total State	46,648,399	10,513,517	3,425,393	32,709,489
Total County and Municipal	169,139	-	-	169,139
Total Taxes	91,619,071	15,558,527	4,289,099	71,771,445
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(153,367)	(67,518)	(28,342)	(57,508)
Total Sales for Resale	281,028,044	281,028,044	-	-
Total Other Revenues	40,556,041	7,321,777	20,086,478	13,147,787
Total Other Included Items	321,430,718	288,282,303	20,058,136	13,090,279
Schedule 4: Average System Cost				
Total Operating Expenses	655,199,136	382,598,471	40,479,991	232,120,674
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	153,733,618	72,012,319	28,590,790	53,130,509
*(Total Rate Base * Rate of Return)*				
Total Cost	$808,932,754	$454,610,790	$69,070,782	$285,251,183
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$523,681,571
Total Retail Load (MWH)	12,981,113
Distribution Losses	649,056
Total Retail Load plus Distribution Losses	13,630,169
Average System Cost before NLSL Adjustment	**$38.42**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$38.42**
Contract System Costs	$523,681,571
Contract System Load	13,630,169
Average System Cost (See note below)	**$38.42**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4B PacifiCorp - Oregon 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$169,453,278	$73,170,499	$31,838,703	$64,444,075
Total Production Plant	1,490,463,502	1,490,463,502	-	-
Total Transmission Plant	648,545,869	-	648,545,869	-
Total Distribution Plant	1,312,708,577	-	-	1,312,708,577
Total General Plant	326,094,546	161,904,897	51,275,471	112,914,178
Total Electric Plant In-Service	3,947,265,772	1,725,538,898	731,660,043	1,490,066,831
LESS:				
Total Depreciation and Amortization	1,706,085,996	833,359,030	285,583,152	587,143,815
Total Net Plant	2,241,179,775	892,179,868	446,076,891	902,923,016
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	37,897,385	17,711,076	4,795,094	15,391,215
Total Utility Plant	148,723,697	50,270,297	2,100,289	96,353,111
Total Other Property and Investments	25,149,835	-	-	25,149,835
Total Current and Accrued Assets	115,728,784	97,138,048	6,147,568	12,443,168
Total Deferred Debits	571,523,513	303,408,499	17,940,735	250,174,279
Total Assets and Other Debits	899,023,214	468,527,920	30,983,686	399,511,608
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	210,980,795	210,980,795	-	-
Total Deferred Credits	464,922,431	37,842,617	2,755,736	424,324,078
Total Liabilities and Other Credits	675,903,226	248,823,412	2,755,736	424,324,078
Total Rate Base	2,464,299,763	1,111,884,376	474,304,841	878,110,546
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,820,085,702
Interest for Year	220,390,393
Rate of Return	5.77%
(Interest/Long Term Debt)	

Table 7.4B PacifiCorp - Oregon 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$588,131,187	$582,887,284	$0	$5,243,903
Total Transmission Expense	30,069,681	-	30,069,681	-
Total Distribution Expense	48,858,670	-	-	48,858,670
Total Customer and Sales Expenses	35,984,392	-	-	35,984,392
Total Administration and General Expenses	75,312,651	33,978,823	8,291,070	33,042,758
Total Operations and Maintenance	778,356,581	616,866,107	38,360,752	123,129,722
Total Depreciation and Amortization	130,013,561	57,266,179	19,185,464	53,561,918
Schedule 3A Items: Taxes				
Total Federal	42,787,072	5,178,469	876,234	36,732,369
Total State	48,640,251	10,606,068	3,519,916	34,514,267
Total County and Municipal	176,249	-	-	176,249
Total Taxes	91,603,571	15,784,537	4,396,150	71,422,884
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	292,358,479	292,358,479	-	-
Total Other Revenues	32,407,405	4,079,747	17,695,236	10,632,422
Total Other Included Items	324,765,884	296,438,226	17,695,236	10,632,422
Schedule 4: Average System Cost				
Total Operating Expenses	675,207,829	393,478,597	44,247,130	237,482,102
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	142,171,678	64,147,418	27,363,844	50,660,415
*(Total Rate Base * Rate of Return)*				
Total Cost	$817,379,506	$457,626,015	$71,610,975	$288,142,517
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$529,236,989
Total Retail Load (MWH)	13,227,231
Distribution Losses	661,362
Total Retail Load plus Distribution Losses	13,888,593
Average System Cost before NLSL Adjustment	**$38.11**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$38.11**
Contract System Costs	$529,236,989
Contract System Load	13,888,593
Average System Cost (See note below)	**$38.11**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4B PacifiCorp - Oregon 2004 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$192,327,995	$80,987,064	$37,574,917	$73,766,014
Total Production Plant	1,508,893,478	1,508,893,478	-	-
Total Transmission Plant	700,069,183	-	700,069,183	-
Total Distribution Plant	1,374,356,004	-	-	1,374,356,004
Total General Plant	342,160,145	168,840,961	54,653,225	118,665,959
Total Electric Plant In-Service	4,117,806,805	1,758,721,503	792,297,325	1,566,787,977
LESS:				
Total Depreciation and Amortization	1,775,123,074	858,550,677	297,691,432	618,880,965
Total Net Plant	2,342,683,731	900,170,825	494,605,894	947,907,011
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	42,888,699	18,317,688	4,839,418	19,731,593
Total Utility Plant	179,784,960	49,636,841	2,145,081	128,003,039
Total Other Property and Investments	95,722,076	69,522,236	-	26,199,841
Total Current and Accrued Assets	99,064,225	69,222,880	10,070,744	19,770,600
Total Deferred Debits	659,246,216	175,623,458	18,549,200	465,073,558
Total Assets and Other Debits	1,076,706,177	382,323,104	35,604,442	658,778,630
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	155,489,291	155,489,291	-	-
Total Current and Accrued Liabilities	24,247,263	24,247,263	-	-
Total Deferred Credits	605,104,893	30,963,413	3,221,630	570,919,850
Total Liabilities and Other Credits	784,841,447	210,699,967	3,221,630	570,919,850
Total Rate Base	2,634,548,460	1,071,793,962	526,988,706	1,035,765,792
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,933,071,649
Interest for Year	229,563,698
Rate of Return	5.84%
(Interest/Long Term Debt)	

Table 7.4B PacifiCorp - Oregon 2004 (continued)
Average System Cost Cookbook Summary

Schedule 3: Expenses

Total Production Expense	$447,161,656	$440,047,835	$0	$7,113,821
Total Transmission Expense	29,722,637	-	29,722,637	-
Total Distribution Expense	74,954,760	-	-	74,954,760
Total Customer and Sales Expenses	41,248,311	-	-	41,248,311
Total Administration and General Expenses	74,806,322	31,277,766	8,992,705	34,535,850
Total Operations and Maintenance	667,893,686	471,325,601	38,715,342	157,852,743
Total Depreciation and Amortization	130,031,707	57,777,626	19,981,222	52,272,859

Schedule 3A Items: Taxes

Total Federal	32,548,658	72,472	13,293	32,462,894
Total State	46,509,179	10,092,404	3,503,143	32,913,632
Total County and Municipal	68,409	-	-	68,409
Total Taxes	79,126,247	10,164,876	3,516,436	65,444,935

Schedule 3B Items: Other Included Items

Total Disposition of Plant	-	-	-	-
Total Sales for Resale	93,916,226	93,916,226	-	-
Total Other Revenues	45,613,172	10,027,495	19,525,132	16,060,546
Total Other Included Items	139,529,398	103,943,721	19,525,132	16,060,546

Schedule 4: Average System Cost

Total Operating Expenses	737,522,242	435,324,383	42,687,868	259,509,991

(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)

Return on Rate Base	153,772,100	62,557,972	30,759,032	60,455,096

*(Total Rate Base * Rate of Return)*

Total Cost	$891,294,342	$497,882,355	$73,446,900	$319,965,087

(Total Operating Expenses + Return on Rate Base)

Total Production and Transmission Costs	$571,329,255
Total Retail Load (MWH)	13,133,938
Distribution Losses	656,697
Total Retail Load plus Distribution Losses	13,790,635
Average System Cost before NLSL Adjustment	**$41.43**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$41.43**
Contract System Costs	$571,329,255
Contract System Load	13,790,635
Average System Cost (See note below)	**$41.43**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4B PacifiCorp - Oregon 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$200,031,016	$84,238,027	$38,878,857	$76,914,132
Total Production Plant	1,572,092,345	1,572,092,345	-	-
Total Transmission Plant	725,576,742	-	725,576,742	-
Total Distribution Plant	1,435,410,129	-	-	1,435,410,129
Total General Plant	345,343,269	161,430,514	58,051,963	125,860,792
Total Electric Plant In-Service	4,278,453,500	1,817,760,886	822,507,562	1,638,185,053
LESS:				
Total Depreciation and Amortization	1,835,562,477	901,006,153	373,497,626	561,058,698
Total Net Plant	2,442,891,023	916,754,733	449,009,936	1,077,126,354
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	42,431,474	18,495,709	5,047,382	18,888,383
Total Utility Plant	235,176,282	54,628,757	4,437,810	176,109,715
Total Other Property and Investments	169,551,455	142,066,944	-	27,484,511
Total Current and Accrued Assets	165,160,670	140,703,015	8,211,945	16,245,710
Total Deferred Debits	438,964,892	195,664,725	12,479,769	230,820,397
Total Assets and Other Debits	1,051,284,773	551,559,150	30,176,906	469,548,717
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	150,017,262	150,017,262	-	-
Total Current and Accrued Liabilities	59,143,331	59,143,331	-	-
Total Deferred Credits	652,230,347	48,127,211	2,676,296	601,426,840
Total Liabilities and Other Credits	861,390,940	257,287,804	2,676,296	601,426,840
Total Rate Base	2,632,784,856	1,211,026,079	476,510,546	945,248,231
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,052,276,242
Interest for Year	237,603,134
Rate of Return	5.86%
(Interest/Long Term Debt)	

Table 7.4B PacifiCorp - Oregon 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$543,501,858	$536,306,736	$0	$7,195,122
Total Transmission Expense	32,519,854	-	32,519,854	-
Total Distribution Expense	63,857,005	-	-	63,857,005
Total Customer and Sales Expenses	46,171,727	-	-	46,171,727
Total Administration and General Expenses	72,306,360	30,563,949	7,859,202	33,883,209
Total Operations and Maintenance	758,356,804	566,870,684	40,379,056	151,107,063
Total Depreciation and Amortization	128,642,849	58,009,028	19,926,720	50,707,101
Schedule 3A Items: Taxes				
Total Federal	40,122,501	4,465,512	827,036	34,829,954
Total State	45,178,453	9,821,630	3,435,691	31,921,132
Total County and Municipal	93,771	-	-	93,771
Total Taxes	85,394,725	14,287,142	4,262,726	66,844,856
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(16,911)	(7,185)	(3,251)	(6,475)
Total Sales for Resale	176,406,213	176,406,213	-	-
Total Other Revenues	53,270,750	10,138,830	24,254,224	18,877,696
Total Other Included Items	229,660,052	186,537,858	24,250,973	18,871,221
Schedule 4: Average System Cost				
Total Operating Expenses	742,734,326	452,628,997	40,317,529	249,787,799
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	154,371,986	71,007,892	27,939,951	55,424,144
*(Total Rate Base * Rate of Return)*				
Total Cost	$897,106,312	$523,636,889	$68,257,480	$305,211,943
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$591,894,369
Total Retail Load (MWH)	13,206,589
Distribution Losses	660,329
Total Retail Load plus Distribution Losses	13,866,918
Average System Cost before NLSL Adjustment	**$42.68**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$42.68**
Contract System Costs	$591,894,369
Contract System Load	13,866,918
Average System Cost (See note below)	**$42.68**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4B PacifiCorp - Oregon 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$202,279,495	$89,015,809	$37,169,211	$76,094,475
Total Production Plant	1,757,056,278	1,757,056,278	-	-
Total Transmission Plant	733,671,878	-	733,671,878	-
Total Distribution Plant	1,502,005,950	-	-	1,502,005,950
Total General Plant	346,356,217	163,265,386	56,955,892	126,134,939
Total Electric Plant In-Service	4,541,369,817	2,009,337,473	827,796,981	1,704,235,363
LESS:				
Total Depreciation and Amortization	1,916,331,558	940,202,008	389,165,116	586,964,433
Total Net Plant	2,625,038,259	1,069,135,465	438,631,864	1,117,270,930
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	45,798,995	19,633,992	5,840,648	20,324,355
Total Utility Plant	274,280,381	57,682,730	5,314,624	211,283,027
Total Other Property and Investments	91,706,845	64,101,333	-	27,605,511
Total Current and Accrued Assets	123,797,120	90,101,736	11,057,656	22,637,729
Total Deferred Debits	674,795,109	166,659,240	30,019,624	478,116,245
Total Assets and Other Debits	1,210,378,451	398,179,031	52,232,553	759,966,868
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	137,660,109	137,660,109	-	-
Total Current and Accrued Liabilities	29,886,778	29,886,778	-	-
Total Deferred Credits	718,144,528	29,373,545	3,720,397	685,050,585
Total Liabilities and Other Credits	885,691,415	196,920,432	3,720,397	685,050,585
Total Rate Base	2,949,725,296	1,270,394,063	487,144,020	1,192,187,212
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,086,372,000
Interest for Year	245,313,780
Rate of Return	6.00%
(Interest/Long Term Debt)	

Table 7.4B PacifiCorp - Oregon 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$578,453,478	$570,748,193	$0	$7,705,285
Total Transmission Expense	39,159,870	-	39,159,870	-
Total Distribution Expense	69,089,133	-	-	69,089,133
Total Customer and Sales Expenses	52,465,272	-	-	52,465,272
Total Administration and General Expenses	71,262,031	30,361,563	7,565,317	33,335,151
Total Operations and Maintenance	810,429,785	601,109,756	46,725,188	162,594,841
Total Depreciation and Amortization	133,906,171	61,667,764	20,300,911	51,937,496
Schedule 3A Items: Taxes				
Total Federal	64,675,441	4,500,153	849,247	59,326,041
Total State	56,606,346	11,506,157	3,751,546	41,348,644
Total County and Municipal	373,548	-	-	373,548
Total Taxes	121,655,335	16,006,309	4,600,793	101,048,234
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	214,746,418	214,746,418	-	-
Total Other Revenues	41,975,058	9,237,385	17,337,882	15,399,791
Total Other Included Items	256,721,476	223,983,803	17,337,882	15,399,791
Schedule 4: Average System Cost				
Total Operating Expenses	809,269,816	454,800,026	54,289,009	300,180,780
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	177,078,411	76,264,513	29,244,313	71,569,586
*(Total Rate Base * Rate of Return)*				
Total Cost	$986,348,227	$531,064,539	$83,533,322	$371,750,366
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$614,597,861
Total Retail Load (MWH)	13,912,000
Distribution Losses	695,600
Total Retail Load plus Distribution Losses	14,607,600
Average System Cost before NLSL Adjustment	**$42.07**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$42.07**
Contract System Costs	$614,597,861
Contract System Load	14,607,600
Average System Cost (See note below)	**$42.07**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4C PacifiCorp - Washington 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$38,180,014	$17,882,523	$8,140,430	$12,157,061
Total Production Plant	431,916,024	431,916,024	-	-
Total Transmission Plant	196,615,544	-	196,615,544	-
Total Distribution Plant	293,629,125	-	-	293,629,125
Total General Plant	90,543,609	48,169,678	15,916,829	26,457,102
Total Electric Plant In-Service	1,050,884,316	497,968,225	220,672,803	332,243,289
LESS:				
Total Depreciation and Amortization	450,888,697	240,413,653	82,875,804	127,599,240
Total Net Plant	599,995,619	257,554,572	137,796,999	204,644,048
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	9,106,170	4,739,747	1,446,846	2,919,578
Total Utility Plant	42,963,203	14,499,479	325,790	28,137,935
Total Other Property and Investments	6,486,851	-	-	6,486,851
Total Current and Accrued Assets	32,500,613	27,702,023	1,924,503	2,874,087
Total Deferred Debits	109,632,262	60,256,751	2,252,081	47,123,431
Total Assets and Other Debits	200,689,100	107,197,999	5,949,220	87,541,882
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	63,119,836	63,119,836	-	-
Total Deferred Credits	119,255,381	7,010,360	2,310,260	109,934,761
Total Liabilities and Other Credits	182,375,216	70,130,196	2,310,260	109,934,761
Total Rate Base	618,309,503	294,622,375	141,435,959	182,251,169
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,895,711,464
Interest for Year	252,443,726
Rate of Return	6.48%
(Interest/Long Term Debt)	

Table 7.4C PacifiCorp - Washington 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$170,944,058	$170,944,058	$0	$0
Total Transmission Expense	8,827,942	-	8,827,942	-
Total Distribution Expense	7,123,248	-	-	7,123,248
Total Customer and Sales Expenses	7,252,325	-	-	7,252,325
Total Administration and General Expenses	22,137,201	10,409,326	2,746,825	8,981,050
Total Operations and Maintenance	216,284,773	181,353,384	11,574,766	23,356,623
Total Depreciation and Amortization	35,383,065	16,237,633	5,573,882	13,571,549
Schedule 3A Items: Taxes				
Total Federal	11,987,390	1,421,852	258,909	10,306,628
Total State	12,821,195	2,762,097	933,323	9,125,775
Total County and Municipal	53,451	-	-	53,451
Total Taxes	24,862,036	4,183,950	1,192,231	19,485,855
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(48,467)	(22,966)	(10,177)	(15,323)
Total Sales for Resale	85,240,678	85,240,678	-	-
Total Other Revenues	11,900,634	2,490,529	6,366,909	3,043,195
Total Other Included Items	97,092,846	87,708,241	6,356,732	3,027,872
Schedule 4: Average System Cost				
Total Operating Expenses	179,437,028	114,066,726	11,984,148	53,386,154
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	40,066,713	19,091,653	9,165,109	11,809,952
*(Total Rate Base * Rate of Return)*				
Total Cost	$219,503,742	$133,158,379	$21,149,257	$65,196,106
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$154,307,636
Total Retail Load (MWH)	3,941,255
Distribution Losses	197,063
Total Retail Load plus Distribution Losses	4,138,318
Average System Cost before NLSL Adjustment	**$37.29**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$37.29**
Contract System Costs	$154,307,636
Contract System Load	4,138,318
Average System Cost (See note below)	**$37.29**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4C PacifiCorp - Washington 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$42,665,033	$19,840,095	$9,130,405	$13,694,534
Total Production Plant	445,355,903	445,355,903	-	-
Total Transmission Plant	204,952,644	-	204,952,644	-
Total Distribution Plant	307,404,854	-	-	307,404,854
Total General Plant	93,804,986	49,975,349	16,496,570	27,333,067
Total Electric Plant In-Service	1,094,183,420	515,171,347	230,579,619	348,432,455
LESS:				
Total Depreciation and Amortization	477,089,067	254,321,956	87,303,628	135,463,483
Total Net Plant	617,094,353	260,849,391	143,275,991	212,968,972
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	9,340,279	4,834,050	1,457,900	3,048,328
Total Utility Plant	44,384,073	14,478,692	319,790	29,585,591
Total Other Property and Investments	6,890,338	-	-	6,890,338
Total Current and Accrued Assets	36,238,404	30,885,551	2,141,242	3,211,611
Total Deferred Debits	125,756,720	68,494,966	4,934,581	52,327,174
Total Assets and Other Debits	222,609,814	118,693,259	8,853,513	95,063,042
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	66,673,884	66,673,884	-	-
Total Deferred Credits	119,664,995	10,598,581	709,715	108,356,699
Total Liabilities and Other Credits	186,338,879	77,272,465	709,715	108,356,699
Total Rate Base	653,365,289	302,270,185	151,419,789	199,675,315
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,820,085,702
Interest for Year	220,390,393
Rate of Return	5.77%
(Interest/Long Term Debt)	

Table 7.4C PacifiCorp - Washington 2003 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$174,785,226	$174,785,226	$0	$0
Total Transmission Expense	9,120,656	-	9,120,656	-
Total Distribution Expense	7,342,639	-	-	7,342,639
Total Customer and Sales Expenses	8,453,938	-	-	8,453,938
Total Administration and General Expenses	20,846,074	9,713,478	2,542,548	8,590,049
Total Operations and Maintenance	220,548,532	184,498,703	11,663,203	24,386,626
Total Depreciation and Amortization	35,007,449	17,292,718	5,868,210	11,846,522
Schedule 3A Items: Taxes				
Total Federal	11,456,670	1,455,675	260,072	9,740,923
Total State	13,136,019	2,740,846	940,610	9,454,563
Total County and Municipal	55,698	-	-	55,698
Total Taxes	24,648,386	4,196,521	1,200,682	19,251,184
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	88,677,396	88,677,396	-	-
Total Other Revenues	9,341,445	1,388,607	5,577,864	2,374,974
Total Other Included Items	98,018,840	90,066,002	5,577,864	2,374,974
Schedule 4: Average System Cost				
Total Operating Expenses	182,185,528	115,921,940	13,154,231	53,109,357
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	37,694,294	17,438,730	8,735,790	11,519,773
*(Total Rate Base * Rate of Return)*				
Total Cost	$219,879,822	$133,360,670	$21,890,021	$64,629,130
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$155,250,691
Total Retail Load (MWH)	4,144,732
Distribution Losses	207,237
Total Retail Load plus Distribution Losses	4,351,969
Average System Cost before NLSL Adjustment	**$35.67**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$35.67**
Contract System Costs	$155,250,691
Contract System Load	4,351,969
Average System Cost (See note below)	**$35.67**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4C PacifiCorp - Washington 2004 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$49,605,958	$22,794,383	$10,526,086	$16,285,489
Total Production Plant	450,472,927	450,472,927	-	-
Total Transmission Plant	208,021,279	-	208,021,279	-
Total Distribution Plant	321,841,203	-	-	321,841,203
Total General Plant	96,970,712	51,042,558	16,802,094	29,126,060
Total Electric Plant In-Service	1,126,912,079	524,309,869	235,349,459	367,252,751
LESS:				
Total Depreciation and Amortization	490,126,944	257,594,312	89,389,011	143,143,622
Total Net Plant	636,785,135	266,715,557	145,960,449	224,109,129
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	10,014,531	4,783,571	1,433,610	3,797,350
Total Utility Plant	51,687,683	14,111,791	310,893	37,264,999
Total Other Property and Investments	27,579,430	20,658,107	-	6,921,322
Total Current and Accrued Assets	28,713,325	20,825,418	3,096,752	4,791,156
Total Deferred Debits	162,421,560	42,020,162	4,936,689	115,464,709
Total Assets and Other Debits	280,416,530	102,399,049	9,777,944	168,239,537
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	46,202,692	46,202,692	-	-
Total Current and Accrued Liabilities	7,204,926	7,204,926	-	-
Total Deferred Credits	177,740,468	8,351,727	928,503	168,460,238
Total Liabilities and Other Credits	231,148,087	61,759,345	928,503	168,460,238
Total Rate Base	686,053,577	307,355,260	154,809,889	223,888,428
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$3,933,071,649
Interest for Year	229,563,698
Rate of Return	5.84%
(Interest/Long Term Debt)	

Table 7.4C PacifiCorp - Washington 2004 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$126,221,658	$126,221,658	$0	$0
Total Transmission Expense	8,873,551	-	8,873,551	-
Total Distribution Expense	11,822,559	-	-	11,822,559
Total Customer and Sales Expenses	9,820,048	-	-	9,820,048
Total Administration and General Expenses	20,144,178	8,812,653	2,595,330	8,736,195
Total Operations and Maintenance	176,881,995	135,034,311	11,468,881	30,378,803
Total Depreciation and Amortization	34,842,558	17,253,028	5,974,577	11,614,953
Schedule 3A Items: Taxes				
Total Federal	8,947,204	19,898	3,747	8,923,558
Total State	34,637,687	823,981	114,425	33,699,281
Total County and Municipal	20,327	-	-	20,327
Total Taxes	43,605,218	843,879	118,173	42,643,166
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	28,038,240	28,038,240	-	-
Total Other Revenues	12,956,695	3,245,833	6,012,277	3,698,585
Total Other Included Items	40,994,934	31,284,073	6,012,277	3,698,585
Schedule 4: Average System Cost				
Total Operating Expenses	214,334,837	121,847,146	11,549,353	80,938,338
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	40,043,256	17,939,569	9,035,872	13,067,816
*(Total Rate Base * Rate of Return)*				
Total Cost	$254,378,093	$139,786,715	$20,585,225	$94,006,153
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$160,371,940
Total Retail Load (MWH)	4,060,413
Distribution Losses	203,021
Total Retail Load plus Distribution Losses	4,263,434
Average System Cost before NLSL Adjustment	**$37.62**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$37.62**
Contract System Costs	$160,371,940
Contract System Load	4,263,434
Average System Cost (See note below)	**$37.62**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4C PacifiCorp - Washington 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$53,588,670	$24,241,546	$11,467,844	$17,879,280
Total Production Plant	455,752,107	455,752,107	-	-
Total Transmission Plant	215,600,694	-	215,600,694	-
Total Distribution Plant	336,138,614	-	-	336,138,614
Total General Plant	98,880,406	49,070,287	18,250,731	31,559,388
Total Electric Plant In-Service	1,159,960,491	529,063,940	245,319,269	385,577,282
LESS:				
Total Depreciation and Amortization	518,399,897	268,402,546	91,276,473	158,720,878
Total Net Plant	641,560,595	260,661,395	154,042,796	226,856,404
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	10,409,342	4,815,470	1,498,692	4,095,179
Total Utility Plant	67,920,409	15,592,096	1,018,770	51,309,544
Total Other Property and Investments	49,475,023	42,214,324	-	7,260,699
Total Current and Accrued Assets	48,777,954	42,066,178	2,622,731	4,089,046
Total Deferred Debits	105,673,701	46,341,369	3,266,842	56,065,490
Total Assets and Other Debits	282,256,430	151,029,437	8,407,035	122,819,958
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	44,576,712	44,576,712	-	-
Total Current and Accrued Liabilities	17,574,079	17,574,079	-	-
Total Deferred Credits	187,825,707	13,893,588	634,394	173,297,724
Total Liabilities and Other Credits	249,976,499	76,044,380	634,394	173,297,724
Total Rate Base	673,840,526	335,646,451	161,815,437	176,378,637
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,052,276,242
Interest for Year	237,603,134
Rate of Return	5.86%
(Interest/Long Term Debt)	

Table 7.4C PacifiCorp - Washington 2005 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$154,893,786	$154,893,786	$0	$0
Total Transmission Expense	9,708,647	-	9,708,647	-
Total Distribution Expense	13,065,375	-	-	13,065,375
Total Customer and Sales Expenses	10,992,174	-	-	10,992,174
Total Administration and General Expenses	19,470,977	8,486,198	2,280,893	8,703,887
Total Operations and Maintenance	208,130,959	163,379,984	11,989,540	32,761,436
Total Depreciation and Amortization	35,398,735	17,242,958	5,956,082	12,199,695
Schedule 3A Items: Taxes				
Total Federal	10,988,204	1,221,615	234,726	9,531,863
Total State	12,861,601	2,453,531	865,739	9,542,331
Total County and Municipal	27,864	-	-	27,864
Total Taxes	23,877,669	3,675,146	1,100,465	19,102,058
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(5,025)	(2,292)	(1,063)	(1,670)
Total Sales for Resale	52,665,231	52,665,231	-	-
Total Other Revenues	15,635,105	3,234,221	7,500,887	4,899,997
Total Other Included Items	68,295,311	55,897,159	7,499,824	4,898,327
Schedule 4: Average System Cost				
Total Operating Expenses	199,112,052	128,400,929	11,546,262	59,164,861
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	39,510,293	19,680,457	9,487,965	10,341,871
*(Total Rate Base * Rate of Return)*				
Total Cost	$238,622,345	$148,081,386	$21,034,227	$69,506,732
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$169,115,613
Total Retail Load (MWH)	4,244,500
Distribution Losses	212,225
Total Retail Load plus Distribution Losses	4,456,725
Average System Cost before NLSL Adjustment	**$37.95**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$37.95**
Contract System Costs	$169,115,613
Contract System Load	4,456,725
Average System Cost (See note below)	**$37.95**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.4C PacifiCorp - Washington 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$54,062,173	$25,462,488	$10,970,452	$17,629,234
Total Production Plant	508,020,757	508,020,757	-	-
Total Transmission Plant	218,879,519	-	218,879,519	-
Total Distribution Plant	351,733,757	-	-	351,733,757
Total General Plant	99,278,609	49,764,849	17,954,383	31,559,377
Total Electric Plant In-Service	1,231,974,816	583,248,095	247,804,354	400,922,368
LESS:				
Total Depreciation and Amortization	533,645,023	272,598,821	94,970,087	166,076,115
Total Net Plant	698,329,793	310,649,273	152,834,267	234,846,253
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	10,997,044	4,985,961	1,690,578	4,320,505
Total Utility Plant	78,678,665	15,776,048	1,195,107	61,707,511
Total Other Property and Investments	26,541,639	19,123,629	-	7,418,010
Total Current and Accrued Assets	36,198,998	27,089,907	3,494,124	5,614,967
Total Deferred Debits	173,103,043	45,403,055	7,845,232	119,854,756
Total Assets and Other Debits	325,519,389	112,378,600	14,225,041	198,915,749
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	41,068,738	41,068,738	-	-
Total Current and Accrued Liabilities	8,916,252	8,916,252	-	-
Total Deferred Credits	204,412,744	6,934,801	1,147,258	196,330,684
Total Liabilities and Other Credits	254,397,734	56,919,792	1,147,258	196,330,684
Total Rate Base	769,451,449	366,108,082	165,912,049	237,431,318
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$4,086,372,000
Interest for Year	245,313,780
Rate of Return	6.00%
(Interest/Long Term Debt)	

Table 7.4C PacifiCorp - Washington 2006 (continued)
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$161,403,872	$161,403,872	$0	$0
Total Transmission Expense	11,326,130	-	11,326,130	-
Total Distribution Expense	14,031,027	-	-	14,031,027
Total Customer and Sales Expenses	11,948,136	-	-	11,948,136
Total Administration and General Expenses	19,222,904	8,439,532	2,198,497	8,584,875
Total Operations and Maintenance	217,932,069	169,843,404	13,524,627	34,564,038
Total Depreciation and Amortization	36,287,989	17,868,354	5,925,506	12,494,128
Schedule 3A Items: Taxes				
Total Federal	16,547,048	1,233,328	241,120	15,072,600
Total State	14,134,244	2,437,335	803,362	10,893,547
Total County and Municipal	111,442	-	-	111,442
Total Taxes	30,792,734	3,670,663	1,044,482	26,077,590
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	-	-	-	-
Total Sales for Resale	62,110,672	62,110,672	-	-
Total Other Revenues	12,180,009	2,948,749	5,270,059	3,961,201
Total Other Included Items	74,290,681	65,059,421	5,270,059	3,961,201
Schedule 4: Average System Cost				
Total Operating Expenses	210,722,111	126,323,000	15,224,556	69,174,555
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	46,191,840	21,978,263	9,960,060	14,253,517
*(Total Rate Base * Rate of Return)*				
Total Cost	$256,913,952	$148,301,263	$25,184,616	$83,428,072
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$173,485,879
Total Retail Load (MWH)	4,166,057
Distribution Losses	208,303
Total Retail Load plus Distribution Losses	4,374,360
Average System Cost before NLSL Adjustment	**$39.66**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$39.66**
Contract System Costs	$173,485,879
Contract System Load	4,374,360
Average System Cost (See note below)	**$39.66**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.5 Portland General Electric 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$114,232,096	$46,999,470	$12,187,258	$55,045,369
Total Production Plant	1,346,526,119	1,346,526,119	-	-
Total Transmission Plant	349,162,680	-	349,162,680	-
Total Distribution Plant	1,577,039,635	-	-	1,577,039,635
Total General Plant	238,093,548	70,729,216	27,362,626	140,001,705
Total Electric Plant In-Service	3,625,054,078	1,464,254,805	388,712,564	1,772,086,709
LESS:				
Total Depreciation and Amortization	1,767,363,405	821,725,519	165,683,696	779,954,190
Total Net Plant	1,857,690,673	642,529,286	223,028,868	992,132,518
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	44,757,292	15,629,964	9,162,524	19,964,804
Total Utility Plant	80,778,431	79,332	21,060	80,678,039
Total Other Property and Investments	22,719,073	-	-	22,719,073
Total Current and Accrued Assets	211,957,669	144,119,851	12,296,897	55,540,921
Total Deferred Debits	700,077,028	357,568,486	6,749,774	335,758,768
Total Assets and Other Debits	1,060,289,493	517,397,632	28,230,255	514,661,605
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	79,936,089	79,936,089	-	-
Total Deferred Credits	564,308,241	31,148,065	60,388	533,099,788
Total Liabilities and Other Credits	644,244,330	111,084,154	60,388	533,099,788
Total Rate Base	2,273,735,836	1,048,842,765	251,198,735	973,694,336
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$1,019,113,764
Interest for Year	62,075,102
Rate of Return	6.09%
(Interest/Long Term Debt)	

Table 7.5 Portland General Electric 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$1,194,379,177	$1,189,582,429	$0	$4,796,748
Total Transmission Expense	68,424,354	-	68,424,354	-
Total Distribution Expense	43,607,980	-	-	43,607,980
Total Customer and Sales Expenses	59,805,745	-	-	59,805,745
Total Administration and General Expenses	88,913,724	32,529,926	4,875,841	51,507,957
Total Operations and Maintenance	1,455,130,980	1,222,112,355	73,300,195	159,718,430
Total Depreciation and Amortization	163,182,994	55,067,302	14,758,669	93,357,024
Schedule 3A Items: Taxes				
Total Federal	16,994,619	5,961,716	725,223	10,307,679
Total State	78,557,832	14,784,505	2,791,185	60,982,142
Total County and Municipal	-	-	-	-
Total Taxes	95,552,451	20,746,221	3,516,408	71,289,822
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	60,426	24,408	6,479	29,539
Total Sales for Resale	393,839,799	393,839,799	-	-
Total Other Revenues	78,001,755	26,065,731	13,227,272	38,708,752
Total Other Included Items	471,901,980	419,929,938	13,233,751	38,738,291
Schedule 4: Average System Cost				
Total Operating Expenses	1,241,964,445	877,995,940	78,341,521	285,626,985
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	138,495,219	63,885,921	15,300,733	59,308,565
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,380,459,664	$941,881,861	$93,642,253	$344,935,550
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$1,035,524,114
Total Retail Load (MWH)	18,771,884
Distribution Losses	938,594
Total Retail Load plus Distribution Losses	19,710,478
Average System Cost before NLSL Adjustment	**$52.54**
New Large Single Load(s) (MWH)	22,950.00
Cost of Serving New Large Single Load(s)	$1,205,718
Average System Cost after NLSL Adjustment	**$52.54**
Contract System Costs	$1,034,318,396
Contract System Load	19,687,528
Average System Cost (See note below)	**$52.54**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.5.1 Portland General Electric 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$115,660,421	$46,423,863	$9,459,014	$59,777,544
Total Production Plant	1,359,799,659	1,359,799,659	-	-
Total Transmission Plant	277,063,619	-	277,063,619	-
Total Distribution Plant	1,750,941,813	-	-	1,750,941,813
Total General Plant	240,816,722	69,361,750	21,266,246	150,188,726
Total Electric Plant In-Service	3,744,282,234	1,475,585,272	307,788,879	1,960,908,083
LESS:				
Total Depreciation and Amortization	1,863,811,407	823,763,294	133,492,969	906,555,143
Total Net Plant	1,880,470,827	651,821,978	174,295,910	1,054,352,939
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	46,030,211	16,013,553	8,906,844	21,109,813
Total Utility Plant	89,779,810	77,400	16,145	89,686,265
Total Other Property and Investments	9,893,456	-	-	9,893,456
Total Current and Accrued Assets	208,087,865	134,546,838	10,047,052	63,493,976
Total Deferred Debits	566,450,385	207,171,545	6,739,211	352,539,629
Total Assets and Other Debits	920,241,727	357,809,335	25,709,252	536,723,139
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	44,006,368	44,006,368	-	-
Total Deferred Credits	572,468,144	37,717,386	1,150,506	533,600,251
Total Liabilities and Other Credits	616,474,512	81,723,754	1,150,506	533,600,251
Total Rate Base	2,184,238,042	927,907,559	198,854,655	1,057,475,828
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$985,093,544
Interest for Year	73,633,826
Rate of Return	7.47%
(Interest/Long Term Debt)	

Table 7.5.1 Portland General Electric 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$1,163,164,669	$1,155,237,840	$0	$7,926,829
Total Transmission Expense	67,606,405	-	67,606,405	-
Total Distribution Expense	45,720,772	-	-	45,720,772
Total Customer and Sales Expenses	57,547,368	-	-	57,547,368
Total Administration and General Expenses	92,774,927	31,443,041	3,648,349	57,683,536
Total Operations and Maintenance	1,426,814,141	1,186,680,881	71,254,754	168,878,506
Total Depreciation and Amortization	163,888,082	51,991,827	11,001,464	100,894,790
Schedule 3A Items: Taxes				
Total Federal	51,463,611	5,130,039	545,765	45,787,806
Total State	89,110,271	15,545,297	2,339,120	71,225,854
Total County and Municipal	-	-	-	-
Total Taxes	140,573,882	20,675,337	2,884,885	117,013,660
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(1,076,760)	(424,341)	(88,512)	(563,907)
Total Sales for Resale	484,146,313	484,146,313	-	-
Total Other Revenues	69,290,048	22,189,515	10,453,210	36,647,322
Total Other Included Items	552,359,601	505,911,488	10,364,698	36,083,415
Schedule 4: Average System Cost				
Total Operating Expenses	1,178,916,504	753,436,558	74,776,406	350,703,541
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	163,267,544	69,359,285	14,863,999	79,044,261
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,342,184,048	$822,795,842	$89,640,404	$429,747,802
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$912,436,247
Total Retail Load (MWH)	18,425,854
Distribution Losses	921,293
Total Retail Load plus Distribution Losses	19,347,147
Average System Cost before NLSL Adjustment	**$47.16**
New Large Single Load(s) (MWH)	22,950.00
Cost of Serving New Large Single Load(s)	$1,082,351
Average System Cost after NLSL Adjustment	**$47.16**
Contract System Costs	$911,353,895
Contract System Load	19,324,197
Average System Cost (See note below)	**$47.16**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.5.2 Portland General Electric 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$119,518,910	$46,768,594	$9,634,824	$63,115,492
Total Production Plant	1,375,591,237	1,375,591,237	-	-
Total Transmission Plant	283,386,323	-	283,386,323	-
Total Distribution Plant	1,856,397,869	-	-	1,856,397,869
Total General Plant	243,209,439	66,823,893	21,468,678	154,916,868
Total Electric Plant In-Service	3,878,103,778	1,489,183,724	314,489,825	2,074,430,229
LESS:				
Total Depreciation and Amortization	2,002,717,748	865,184,618	140,803,015	996,730,115
Total Net Plant	1,875,386,030	623,999,106	173,686,810	1,077,700,114
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	47,986,872	16,720,132	8,688,192	22,578,547
Total Utility Plant	113,886,040	72,111	15,229	113,798,700
Total Other Property and Investments	1,822,827	-	-	1,822,827
Total Current and Accrued Assets	226,103,642	147,918,112	10,354,608	67,830,922
Total Deferred Debits	496,872,469	150,246,994	4,999,212	341,626,263
Total Assets and Other Debits	886,671,850	314,957,349	24,057,241	547,657,260
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	37,941,717	37,941,717	-	-
Total Deferred Credits	608,773,699	77,717,222	1,461,764	529,594,713
Total Liabilities and Other Credits	646,715,416	115,658,939	1,461,764	529,594,713
Total Rate Base	2,115,342,464	823,297,516	196,282,287	1,095,762,661
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$922,566,003
Interest for Year	64,609,741
Rate of Return	7.00%

(Interest/Long Term Debt)

Table 7.5.2 Portland General Electric 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$1,028,025,499	$1,017,131,190	$0	$10,894,309
Total Transmission Expense	66,182,394	-	66,182,394	-
Total Distribution Expense	50,630,203	-	-	50,630,203
Total Customer and Sales Expenses	59,924,304	-	-	59,924,304
Total Administration and General Expenses	88,895,355	26,392,649	3,323,143	59,179,562
Total Operations and Maintenance	1,293,657,755	1,043,523,840	69,505,537	180,628,378
Total Depreciation and Amortization	168,791,639	52,011,880	10,319,763	106,459,995
Schedule 3A Items: Taxes				
Total Federal	89,847,351	4,902,241	613,699	84,331,412
Total State	85,209,972	15,626,745	2,403,946	67,179,281
Total County and Municipal	-	-	-	-
Total Taxes	175,057,323	20,528,986	3,017,645	151,510,692
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	7,931,653	3,045,738	643,207	4,242,708
Total Sales for Resale	404,216,567	404,216,567	-	-
Total Other Revenues	77,799,090	24,607,992	11,557,426	41,633,672
Total Other Included Items	489,947,310	431,870,297	12,200,634	45,876,379
Schedule 4: Average System Cost				
Total Operating Expenses	1,147,559,407	684,194,409	70,642,312	392,722,687
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	148,143,036	57,657,706	13,746,168	76,739,162
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,295,702,443	$741,852,114	$84,388,480	$469,461,848
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$826,240,595
Total Retail Load (MWH)	17,764,138
Distribution Losses	888,207
Total Retail Load plus Distribution Losses	18,652,345
Average System Cost before NLSL Adjustment	**$44.30**
New Large Single Load(s) (MWH)	22,950.00
Cost of Serving New Large Single Load(s)	$1,016,613
Average System Cost after NLSL Adjustment	**$44.30**
Contract System Costs	$825,223,982
Contract System Load	18,629,395
Average System Cost (See note below)	**$44.30**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.5.3 Portland General Electric 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$175,845,672	$67,548,133	$13,469,835	$94,827,704
Total Production Plant	1,395,471,756	1,395,471,756	-	-
Total Transmission Plant	278,272,299	-	278,272,299	-
Total Distribution Plant	1,959,038,355	-	-	1,959,038,355
Total General Plant	238,709,940	63,723,653	20,628,528	154,357,759
Total Electric Plant In-Service	4,047,338,022	1,526,743,542	312,370,662	2,208,223,818
LESS:				
Total Depreciation and Amortization	2,137,850,732	901,791,841	148,788,465	1,087,270,426
Total Net Plant	1,909,487,290	624,951,701	163,582,197	1,120,953,392
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	54,503,512	20,732,832	8,881,669	24,889,011
Total Utility Plant	176,769,213	70,838	14,493	176,683,881
Total Other Property and Investments	1,458,444	-	-	1,458,444
Total Current and Accrued Assets	335,964,586	303,661,256	4,017,805	28,285,525
Total Deferred Debits	578,183,927	140,685,930	9,089,660	428,408,337
Total Assets and Other Debits	1,146,879,682	465,150,856	22,003,628	659,725,197
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	129,052,668	129,052,668	-	-
Total Deferred Credits	717,365,994	153,028,448	2,692,035	561,645,511
Total Liabilities and Other Credits	846,418,662	282,081,116	2,692,035	561,645,511
Total Rate Base	2,209,948,310	808,021,441	182,893,791	1,219,033,078
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$891,358,548
Interest for Year	61,129,668
Rate of Return	6.86%
(Interest/Long Term Debt)	

Table 7.5.3 Portland General Electric 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$1,298,868,404	$1,287,730,193	$0	$11,138,211
Total Transmission Expense	65,570,362	-	65,570,362	-
Total Distribution Expense	56,188,191	-	-	56,188,191
Total Customer and Sales Expenses	60,786,920	-	-	60,786,920
Total Administration and General Expenses	109,324,902	32,843,148	5,482,992	70,998,762
Total Operations and Maintenance	1,590,738,779	1,320,573,340	71,053,354	199,112,084
Total Depreciation and Amortization	169,145,413	50,508,436	9,713,779	108,923,197
Schedule 3A Items: Taxes				
Total Federal	92,964,323	4,916,831	813,601	87,233,890
Total State	85,476,959	15,390,433	2,310,105	67,776,421
Total County and Municipal	-	-	-	-
Total Taxes	178,441,282	20,307,264	3,123,706	155,010,312
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(2,945,501)	(1,111,107)	(227,332)	(1,607,063)
Total Sales for Resale	653,943,869	653,943,869	-	-
Total Other Revenues	54,895,515	15,247,344	10,038,825	29,609,346
Total Other Included Items	705,893,883	668,080,106	9,811,493	28,002,284
Schedule 4: Average System Cost				
Total Operating Expenses	1,232,431,591	723,308,935	74,079,347	435,043,310
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	151,558,996	55,414,381	12,542,917	83,601,697
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,383,990,587	$778,723,316	$86,622,264	$518,645,007
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$865,345,580
Total Retail Load (MWH)	17,540,047
Distribution Losses	877,002
Total Retail Load plus Distribution Losses	18,417,049
Average System Cost before NLSL Adjustment	**$46.99**
New Large Single Load(s) (MWH)	22,950.00
Cost of Serving New Large Single Load(s)	$1,078,331
Average System Cost after NLSL Adjustment	**$46.99**
Contract System Costs	$864,267,249
Contract System Load	18,394,099
Average System Cost (See note below)	**$46.99**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.5.4 Portland General Electric 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$171,775,360	$64,674,299	$12,952,440	$94,148,620
Total Production Plant	1,414,111,017	1,414,111,017	-	-
Total Transmission Plant	283,206,605	-	283,206,605	-
Total Distribution Plant	2,058,570,452	-	-	2,058,570,452
Total General Plant	242,134,607	62,609,824	20,571,195	158,953,588
Total Electric Plant In-Service	4,169,798,041	1,541,395,140	316,730,240	2,311,672,661
LESS:				
Total Depreciation and Amortization	2,275,003,740	935,853,299	153,709,033	1,185,441,408
Total Net Plant	1,894,794,301	605,541,841	163,021,208	1,126,231,252
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	60,552,944	24,571,362	10,252,582	25,728,999
Total Utility Plant	412,369,796	69,418	14,264	412,286,114
Total Other Property and Investments	203,017	-	-	203,017
Total Current and Accrued Assets	180,870,946	146,134,503	4,200,896	30,535,547
Total Deferred Debits	664,789,497	197,141,737	11,186,456	456,461,304
Total Assets and Other Debits	1,318,786,200	367,917,020	25,654,199	925,214,981
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	154,906,471	154,906,471	-	-
Total Deferred Credits	611,247,370	28,678,231	3,720,084	578,849,055
Total Liabilities and Other Credits	766,153,841	183,584,702	3,720,084	578,849,055
Total Rate Base	2,447,426,660	789,874,160	184,955,322	1,472,597,178
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$1,004,295,222
Interest for Year	62,371,314
Rate of Return	6.21%
(Interest/Long Term Debt)	

Table 7.5.4 Portland General Electric 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$1,392,012,954	$1,380,021,084	$0	$11,991,870
Total Transmission Expense	76,820,098	-	76,820,098	-
Total Distribution Expense	63,378,119	-	-	63,378,119
Total Customer and Sales Expenses	61,844,133	-	-	61,844,133
Total Administration and General Expenses	104,301,298	30,482,864	5,200,561	68,617,873
Total Operations and Maintenance	1,698,356,602	1,410,503,948	82,020,659	205,831,995
Total Depreciation and Amortization	177,413,408	49,220,124	9,358,242	118,835,042
Schedule 3A Items: Taxes				
Total Federal	117,710,557	4,633,229	780,611	112,296,717
Total State	72,950,385	15,320,698	2,294,946	55,334,740
Total County and Municipal	-	-	-	-
Total Taxes	190,660,942	19,953,927	3,075,558	167,631,457
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(293,588)	(108,527)	(22,300)	(162,761)
Total Sales for Resale	650,409,850	650,409,850	-	-
Total Other Revenues	50,960,514	14,121,818	8,030,494	28,808,202
Total Other Included Items	701,076,776	664,423,141	8,008,193	28,645,441
Schedule 4: Average System Cost				
Total Operating Expenses	1,365,354,176	815,254,858	86,446,265	463,653,052
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	151,996,359	49,054,788	11,486,569	91,455,001
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,517,350,535	$864,309,647	$97,932,834	$555,108,054
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$962,242,481
Total Retail Load (MWH)	18,432,527
Distribution Losses	921,626
Total Retail Load plus Distribution Losses	19,354,153
Average System Cost before NLSL Adjustment	**$49.72**
New Large Single Load(s) (MWH)	22,950.00
Cost of Serving New Large Single Load(s)	$1,141,019
Average System Cost after NLSL Adjustment	**$49.72**
Contract System Costs	$961,101,461
Contract System Load	19,331,203
Average System Cost (See note below)	**$49.72**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.6 Puget Sound Energy 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$20,548,638	$5,885,668	$1,452,323	$13,210,647
Total Production Plant	1,113,740,453	1,113,740,453	-	-
Total Transmission Plant	274,822,052	-	274,822,052	-
Total Distribution Plant	2,499,840,829	-	-	2,499,840,829
Total General Plant	(154,610,099)	(37,879,739)	(9,940,248)	(106,790,112)
Total Electric Plant In-Service	4,063,562,071	1,157,505,860	286,214,623	2,619,841,588
LESS:				
Total Depreciation and Amortization	1,840,732,065	650,909,719	112,800,046	1,077,022,300
Total Net Plant	2,222,830,006	506,596,140	173,414,577	1,542,819,288
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	53,563,866	28,048,872	5,523,039	19,991,955
Total Utility Plant	647,245,440	217,767,160	34,521,197	394,957,084
Total Other Property and Investments	41,526,680	-	-	41,526,680
Total Current and Accrued Assets	61,064,660	35,751,634	2,507,179	22,805,846
Total Deferred Debits	763,270,926	268,991,883	9,151,842	485,127,201
Total Assets and Other Debits	1,566,671,572	550,559,548	51,703,257	964,408,766
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	2,410,030	2,410,030	-	-
Total Deferred Credits	1,043,066,464	59,825,139	5,661,048	977,580,278
Total Liabilities and Other Credits	1,045,476,494	62,235,169	5,661,048	977,580,278
Total Rate Base	2,744,025,084	994,920,520	219,456,787	1,529,647,777
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$2,093,860,000
Interest for Year	182,204,172
Rate of Return	8.70%
(Interest/Long Term Debt)	

Table 7.6 Puget Sound Energy 2002
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$836,177,740	$836,177,740	$0	$0
Total Transmission Expense	41,545,182	-	41,545,182	-
Total Distribution Expense	59,968,030	-	-	59,968,030
Total Customer and Sales Expenses	60,008,880	-	-	60,008,880
Total Administration and General Expenses	54,657,778	12,059,916	2,639,129	39,958,733
Total Operations and Maintenance	1,052,357,610	848,237,656	44,184,311	159,935,643
Total Depreciation and Amortization	141,257,098	42,663,445	9,119,231	89,474,422
Schedule 3A Items: Taxes				
Total Federal	(82,580,914)	2,673,184	543,922	(85,798,020)
Total State	193,737,869	18,409,649	2,316,720	173,011,500
Total County and Municipal	-	-	-	-
Total Taxes	111,156,955	21,082,833	2,860,642	87,213,480
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	206,177	58,730	14,522	132,926
Total Sales for Resale	88,682,767	88,682,767	-	-
Total Other Revenues	16,373,824	(8,319,276)	22,043,806	2,649,294
Total Other Included Items	105,262,768	80,422,221	22,058,328	2,782,219
Schedule 4: Average System Costs				
Total Operating Expenses	1,199,508,895	831,561,713	34,105,857	333,841,326
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	238,780,443	86,576,309	19,096,760	133,107,374
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,438,289,338	$918,138,021	$53,202,617	$466,948,700
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$971,340,638
Total Retail Load (MWH)	19,253,824
Distribution Losses	962,691
Total Retail Load plus Distribution Losses	20,216,515
Average System Cost before NLSL Adjustment	**$48.05**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$48.05**
Contract System Costs	$971,340,638
Contract System Load	20,216,515
Average System Cost (See note below)	**$48.05**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.6 Puget Sound Energy 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$19,184,270	$5,506,954	$1,336,483	$12,340,833
Total Production Plant	1,131,938,765	1,131,938,765	-	-
Total Transmission Plant	274,710,175	-	274,710,175	-
Total Distribution Plant	2,536,623,123	-	-	2,536,623,123
Total General Plant	(137,448,837)	(35,622,513)	(8,642,675)	(93,183,650)
Total Electric Plant In-Service	4,099,905,170	1,173,068,232	284,689,332	2,642,147,606
LESS:				
Total Depreciation and Amortization	1,915,493,306	694,753,456	118,048,872	1,102,690,978
Total Net Plant	2,184,411,864	478,314,776	166,640,460	1,539,456,628
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	57,358,978	29,937,126	5,809,698	21,612,154
Total Utility Plant	682,178,288	228,212,800	36,486,410	417,479,077
Total Other Property and Investments	44,942,191	-	-	44,942,191
Total Current and Accrued Assets	62,551,079	38,172,343	2,382,175	21,996,561
Total Deferred Debits	838,126,507	334,444,116	11,189,225	492,493,166
Total Assets and Other Debits	1,685,157,043	630,766,385	55,867,508	998,523,149
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	3,635,722	3,635,722	-	-
Total Deferred Credits	1,018,122,910	36,649,840	5,685,253	975,787,817
Total Liabilities and Other Credits	1,021,758,632	40,285,562	5,685,253	975,787,817
Total Rate Base	2,847,810,275	1,068,795,599	216,822,715	1,562,191,961
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$2,335,157,709
Interest for Year	170,690,378
Rate of Return	7.31%
(Interest/Long Term Debt)	

Table 7.6 Puget Sound Energy 2003
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$896,684,728	$896,684,728	$0	$0
Total Transmission Expense	43,495,781	-	43,495,781	-
Total Distribution Expense	57,740,065	-	-	57,740,065
Total Customer and Sales Expenses	71,401,564	-	-	71,401,564
Total Administration and General Expenses	61,067,257	14,329,848	2,981,805	43,755,604
Total Operations and Maintenance	1,130,389,395	911,014,576	46,477,586	172,897,233
Total Depreciation and Amortization	144,031,071	45,199,107	8,819,904	90,012,060
Schedule 3A Items: Taxes				
Total Federal	25,653,888	2,899,665	545,796	22,208,428
Total State	191,500,792	24,267,242	2,339,709	164,893,841
Total County and Municipal	-	-	-	-
Total Taxes	217,154,680	27,166,907	2,885,504	187,102,269
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(4,734,298)	(1,354,581)	(328,740)	(3,050,976)
Total Sales for Resale	191,876,710	191,876,710	-	-
Total Other Revenues	35,946,385	2,053,463	9,098,184	24,794,738
Total Other Included Items	223,088,797	192,575,592	8,769,444	21,743,761
Schedule 4: Average System Costs				
Total Operating Expenses	1,268,486,349	790,804,998	49,413,550	428,267,801
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	208,163,162	78,124,541	15,848,844	114,189,776
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,476,649,511	$868,929,539	$65,262,394	$542,457,577
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$934,191,933
Total Retail Load (MWH)	19,591,637
Distribution Losses	979,582
Total Retail Load plus Distribution Losses	20,571,219
Average System Cost before NLSL Adjustment	**$45.41**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$45.41**
Contract System Costs	$934,191,933
Contract System Load	20,571,219
Average System Cost	**$45.41**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.6 Puget Sound Energy 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$28,335,684	$7,994,030	$2,016,408	$18,325,246
Total Production Plant	1,143,775,811	1,143,775,811	-	-
Total Transmission Plant	288,505,193	-	288,505,193	-
Total Distribution Plant	2,621,953,457	-	-	2,621,953,457
Total General Plant	(135,019,392)	(34,233,870)	(8,508,741)	(92,276,781)
Total Electric Plant In-Service	4,217,589,537	1,186,003,710	299,030,342	2,732,555,485
LESS:				
Total Depreciation and Amortization	2,006,378,009	715,882,011	127,761,147	1,162,734,851
Total Net Plant	2,211,211,528	470,121,699	171,269,196	1,569,820,633
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	57,357,955	31,122,459	5,921,318	20,314,178
Total Utility Plant	728,052,157	236,659,732	40,052,506	451,339,918
Total Other Property and Investments	62,016,981	13,765,107	-	48,251,874
Total Current and Accrued Assets	55,511,431	29,114,342	2,616,666	23,780,423
Total Deferred Debits	848,132,126	392,538,494	11,133,586	444,460,047
Total Assets and Other Debits	1,751,070,650	703,200,134	59,724,075	988,146,440
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	249,455	249,455	-	-
Total Current and Accrued Liabilities	19,260,915	19,260,915	-	-
Total Deferred Credits	1,062,210,581	38,563,659	5,275,158	1,018,371,764
Total Liabilities and Other Credits	1,081,720,951	58,074,029	5,275,158	1,018,371,764
Total Rate Base	2,880,561,227	1,115,247,804	225,718,113	1,539,595,310
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$2,377,499,400
Interest for Year	161,737,171
Rate of Return	6.80%
(Interest/Long Term Debt)	

Table 7.6 Puget Sound Energy 2004
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$867,778,875	$867,778,875	$0	$0
Total Transmission Expense	44,632,927	-	44,632,927	-
Total Distribution Expense	61,075,209	-	-	61,075,209
Total Customer and Sales Expenses	57,029,385	-	-	57,029,385
Total Administration and General Expenses	60,537,482	13,391,035	2,737,614	44,408,833
Total Operations and Maintenance	1,091,053,878	881,169,910	47,370,541	162,513,427
Total Depreciation and Amortization	147,343,645	45,667,518	9,102,078	92,574,049
Schedule 3A Items: Taxes				
Total Federal	9,796,715	2,770,899	504,592	6,521,224
Total State	202,120,572	19,547,932	2,459,701	180,112,939
Total County and Municipal	-	-	-	-
Total Taxes	211,917,287	22,318,831	2,964,293	186,634,163
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(4,734,298)	(1,331,304)	(335,665)	(3,067,328)
Total Sales for Resale	115,356,097	115,356,097	-	-
Total Other Revenues	47,584,376	3,619,535	12,057,799	31,907,042
Total Other Included Items	158,206,175	117,644,328	11,722,133	28,839,714
Schedule 4: Average System Costs				
Total Operating Expenses	1,292,108,635	831,511,931	47,714,779	412,881,925
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	195,959,597	75,868,379	15,355,213	104,736,005
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,488,068,232	$907,380,310	$63,069,991	$517,617,931
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$970,450,301
Total Retail Load (MWH)	19,876,790
Distribution Losses	993,840
Total Retail Load plus Distribution Losses	20,870,630
Average System Cost before NLSL Adjustment	**$46.50**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$46.50**
Contract System Costs	$970,450,301
Contract System Load	20,870,630
Average System Cost	**$46.50**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.6 Puget Sound Energy 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$30,282,492	$9,132,015	$2,040,437	$19,110,040
Total Production Plant	1,319,444,433	1,319,444,433	-	-
Total Transmission Plant	294,813,676	-	294,813,676	-
Total Distribution Plant	2,761,125,181	-	-	2,761,125,181
Total General Plant	(136,430,064)	(38,040,948)	(8,308,853)	(90,080,263)
Total Electric Plant In-Service	4,542,095,846	1,366,617,396	305,162,965	2,870,315,484
LESS:				
Total Depreciation and Amortization	2,105,742,831	762,788,528	133,207,295	1,209,747,009
Total Net Plant	2,436,353,015	603,828,869	171,955,671	1,660,568,475
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	58,101,129	29,752,748	6,869,835	21,478,545
Total Utility Plant	867,504,480	263,744,293	41,530,694	562,229,493
Total Other Property and Investments	80,807,501	28,464,159	-	52,343,342
Total Current and Accrued Assets	129,090,210	97,000,997	3,095,723	28,993,490
Total Deferred Debits	936,128,076	422,953,494	21,366,252	491,808,330
Total Assets and Other Debits	2,071,631,396	841,915,691	72,862,504	1,156,853,200
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	9,771,867	9,771,867	-	-
Total Deferred Credits	1,181,457,175	59,353,069	6,631,045	1,115,473,061
Total Liabilities and Other Credits	1,191,229,042	69,124,936	6,631,045	1,115,473,061
Total Rate Base	3,316,755,369	1,376,619,624	238,187,130	1,701,948,615
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$2,503,999,400
Interest for Year	162,147,926
Rate of Return	6.48%
(Interest/Long Term Debt)	

Table 7.6 Puget Sound Energy 2005
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$1,012,054,130	$1,012,054,130	$0	$0
Total Transmission Expense	52,111,661	-	52,111,661	-
Total Distribution Expense	61,087,500	-	-	61,087,500
Total Customer and Sales Expenses	62,543,873	-	-	62,543,873
Total Administration and General Expenses	67,441,589	16,397,580	2,847,019	48,196,990
Total Operations and Maintenance	1,255,238,753	1,028,451,710	54,958,680	171,828,363
Total Depreciation and Amortization	152,347,107	48,334,893	9,218,561	94,793,653
Schedule 3A Items: Taxes				
Total Federal	138,720,821	3,447,190	536,908	134,736,723
Total State	220,509,586	20,747,744	2,449,256	197,312,586
Total County and Municipal	-	-	-	-
Total Taxes	359,230,407	24,194,934	2,986,164	332,049,309
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(992,876)	(298,735)	(66,707)	(627,434)
Total Sales for Resale	177,304,684	177,304,684	-	-
Total Other Revenues	64,487,306	11,333,810	5,394,178	47,759,318
Total Other Included Items	240,799,114	188,339,759	5,327,471	47,131,884
Schedule 4: Average System Costs				
Total Operating Expenses	1,526,017,153	912,641,778	61,835,934	551,539,441
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	214,778,408	89,143,798	15,423,945	110,210,665
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,740,795,561	$1,001,785,576	$77,259,879	$661,750,105
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$1,079,045,455
Total Retail Load (MWH)	20,465,557
Distribution Losses	1,023,278
Total Retail Load plus Distribution Losses	21,488,835
Average System Cost before NLSL Adjustment	**$50.21**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$50.21**
Contract System Costs	$1,079,045,455
Contract System Load	21,488,835
Average System Cost	**$50.21**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

Table 7.6 Puget Sound Energy 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 1: Plant Investment / Rate Base / Rate of Return				
Total Intangible Plant	$29,525,752	$10,232,574	$1,982,321	$17,310,857
Total Production Plant	1,709,677,644	1,709,677,644	-	-
Total Transmission Plant	331,209,903	-	331,209,903	-
Total Distribution Plant	2,892,330,528	-	-	2,892,330,528
Total General Plant	(137,244,959)	(44,403,353)	(8,437,458)	(84,404,148)
Total Electric Plant In-Service	5,099,988,786	1,764,313,571	341,629,682	2,994,045,533
LESS:				
Total Depreciation and Amortization	2,218,809,904	833,161,676	142,128,036	1,243,520,192
Total Net Plant	2,881,178,882	931,151,895	199,501,646	1,750,525,341
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)				
Assets and Other Debits (Comparative Balance Sheet)				
Cash Working Capital	64,283,240	33,494,782	7,631,995	23,156,462
Total Utility Plant	887,975,267	307,243,736	44,435,291	536,296,239
Total Other Property and Investments	6,934,092	6,934,092	-	-
Total Current and Accrued Assets	76,520,443	42,451,428	3,500,497	30,568,517
Total Deferred Debits	1,136,646,117	547,567,933	18,841,199	570,236,985
Total Assets and Other Debits	2,172,359,159	937,691,972	74,408,983	1,160,258,204
LESS:				
Liabilities and Other Credits (Comparative Balance Sheet)				
Total Other Noncurrent Liabilities	-	-	-	-
Total Current and Accrued Liabilities	71,010,055	71,010,055	-	-
Total Deferred Credits	1,178,055,547	55,672,768	5,253,624	1,117,129,154
Total Liabilities and Other Credits	1,249,065,602	126,682,823	5,253,624	1,117,129,154
Total Rate Base	3,804,472,439	1,742,161,044	268,657,004	1,793,654,391
(Total Net Plant +Total Assets and Other Debits - Total Liabilities and Other Credits)				

Schedule 2: Weighted Average Cost of Long Term Debt

Long Term Debt	$2,772,999,400
Interest for Year	167,347,092
Rate of Return	6.03%
(Interest/Long Term Debt)	

Table 7.6 Puget Sound Energy 2006
Average System Cost Cookbook Summary

Account Description	Total	Production	Transmission	Distribution/ Other
Schedule 3: Expenses				
Total Production Expense	$1,144,649,016	$1,144,649,016	$0	$0
Total Transmission Expense	57,969,332	-	57,969,332	-
Total Distribution Expense	65,438,100	-	-	65,438,100
Total Customer and Sales Expenses	71,732,129	-	-	71,732,129
Total Administration and General Expenses	70,097,636	18,929,539	3,086,629	48,081,469
Total Operations and Maintenance	1,409,886,213	1,163,578,555	61,055,961	185,251,698
Total Depreciation and Amortization	167,698,558	59,253,464	9,749,014	98,696,079
Schedule 3A Items: Taxes				
Total Federal	137,284,356	3,542,995	535,549	133,205,812
Total State	252,301,606	21,062,677	2,182,120	229,056,810
Total County and Municipal	-	-	-	-
Total Taxes	389,585,962	24,605,672	2,717,669	362,262,622
Schedule 3B Items: Other Included Items				
Total Disposition of Plant	(592,824)	(205,084)	(39,711)	(348,029)
Total Sales for Resale	202,397,803	202,397,803	-	-
Total Other Revenues	45,654,525	3,350,627	11,703,165	30,600,733
Total Other Included Items	247,459,504	205,543,346	11,663,454	30,252,704
Schedule 4: Average System Costs				
Total Operating Expenses	1,719,711,229	1,041,894,345	61,859,189	615,957,695
(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)				
Return on Rate Base	229,595,217	105,137,269	16,213,119	108,244,829
*(Total Rate Base * Rate of Return)*				
Total Cost	$1,949,306,446	$1,147,031,614	$78,072,308	$724,202,524
(Total Operating Expenses + Return on Rate Base)				

Total Production and Transmission Costs	$1,225,103,922
Total Retail Load (MWH)	21,091,533
Distribution Losses	1,054,577
Total Retail Load plus Distribution Losses	22,146,110
Average System Cost before NLSL Adjustment	**$55.32**
New Large Single Load(s) (MWH)	-
Cost of Serving New Large Single Load(s)	$0
Average System Cost after NLSL Adjustment	**$55.32**
Contract System Costs	$1,225,103,922
Contract System Load	22,146,110
Average System Cost	**$55.32**

Note: ASC is Lesser of ASC before NLSL adjustment and ASC after NLSL adjustment

PART TWO: 2007-2008 LOOKBACK

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8. FY 2007-2008 INTRODUCTION

Part Two of the Lookback Study presents BPA's reform of the first two years of its WP-07 rates to be consistent with the Court's recent decisions. BPA decided the basis for the Court's remand of BPA's WP-02 rates would equally apply to the WP-07 rates if BPA did not reform them at this time. BPA's WP-07 rates continued the WP-02 treatment of REP Settlement costs that the Court found improper. To calculate the improperly allocated amounts, BPA must determine the proper amounts to be allocated to preference customers. BPA determined that the proper amounts can be calculated only after determining the appropriate PF Exchange rate for the period. Because the PF Exchange rate determined in the WP-07 rate proceeding was so intertwined with assumptions regarding the REP Settlement Agreements, BPA decided that the WP-07 PF Exchange must be recalculated.

Part Two sets forth the determination of the PF Exchange rate after removing the effects of the REP settlements. To do so, BPA looks back to 2006, when the final 2007 rates were being determined, and excises the REP settlement assumptions from the rate calculations and replaces them with assumptions that conform to an REP consistent with sections 5(c) and 7(b) of the Northwest Power Act. At this time, the only changed condition regards the decision to exclude the Mid-Columbia resources from the 7(b)(2)(D) resource stack, as was done in the WP-02 re-determination. The rate model, as it existed at the time of the Final Proposal in July 2006, was modified to remove these resources, and the rates were recomputed to achieve the final PF Exchange rate used in this Lookback Study. In addition to the PF Exchange rate, the ASCs for each IOU must be determined. Because the REP settlements had attempted to settle disputes regarding various aspects of the REP, ASCs were not filed during the FY 2007-2008 lookback period. BPA therefore has incorporated FERC Form 1 data into the requirements of the 1984 ASC Methodology and estimated the annual ASCs for each IOU.

8.1 Load Resource

8.1.1 Load Forecast for FY 2007-2010

The WP-02 Supplemental Proposal did not include a 7(b)(2) rate test. Therefore, no load obligation forecasts for FY 2007-2010 were required. The Lookback Study assumes the REP settlement agreements are replaced by an REP. Therefore, load obligation forecasts for FY 2007-2010 are required for conducting the 7(b)(2) rate test.

The load obligation forecasts for FY 2007-2010 were retrieved from BPA's Load and Resource Information System (LARIS), using a load obligation forecast consistent with that used in the 2002 Supplemental Proposal Final Study, WP-02-FS-BPA-09. These load obligation forecasts can be found in Table 2-3 of the WP-02 Supplemental Proposal Final Study, WP-02-FS-BPA-9. Table 2 displays the annual averages for FY 2002-2006 from the WP-02 Final Proposal and those used in this Lookback Study, which includes approximately 1,600 aMW of Slice load.

8.1.2 Load Forecast for FY 2007-2008

There were no changes to the load forecast from the WP-07 Final Proposal. These forecasts can be found in the 2007 Wholesale Power Rate Case Final Proposal, Load Resource Study (WP-07-FS-BPA-01) and Documentation (WP-07-FS-BPA-01A) or the 2007 Supplemental Wholesale Power Rate Case Initial Proposal, Load Resource Study (WP-07-E-BPA-45) and Documentation (WP-07-E-BPA-45A).

8.1.3 Federal System Resources for FY 2007-2008

There were no changes to Federal System resources from the WP-07 Final Proposal. These resources can be found in the 2007 Wholesale Power Rate Case Final Proposal, Load Resource Study (WP-07-FS-BPA-01) and Documentation (WP-07-FS-BPA-01A), or the 2007

Supplemental Wholesale Power Rate Case Initial Proposal, Supplemental Load Resource Study (WP-07-E-BPA-45) and Documentation (WP-07-E-BPA-45A).

8.2 Revenue Requirements

8.2.1 Revenue Requirement Forecast for FY 2007-2008

BPA is not proposing any changes to the Revenue Requirement (WP-07-FS-BPA-02) or Revenue Requirement Study Documentation (WP-07-FS-BPA-02A and WP-07-FS-BPA-02B) published in the WP-07 Final Proposal.

8.3 Market Price Forecast

8.3.1 Market Price Forecast for FY 2007-2008

BPA is not proposing any changes to the Market Price Forecast Study (WP-07-FS-BPA-03) or Market Price Forecast Study Documentation (WP-07-FS-BPA-03A) published in the WP-07 Final Proposal.

9. WHOLESALE POWER RATE DEVELOPMENT STUDY, FY 2007-2008

9.1 Average System Cost and Exchange Load Forecasts for 2007-2008

This section discusses the correction of errors to data inputs, functionalization codes, and the load forecast of total retail load and REP loads of the region's IOUs.

New forecasts for 2007-2008 ASCs were determined as part of Lookback process. The WP-07 Final Proposal forecast of the 2007-2008 ASCs was revised, as well as the load forecasts for Contract System Load and REP loads. The ASC forecasts and the REP loads are used in the determination of the 2007-2008 PF Exchange Rate in this Final Proposal.

Development of the 2007-2013 ASC forecasts is a two-step process. First, base year ASCs are developed for the six IOUs. The base year ASCs for each IOU were developed using 2004 FERC Form 1 filings. Data from the utilities' FERC Form 1s were entered into the Cookbook Model to determine Contract System Costs. The data were analyzed and functionalized in accordance with the 1984 ASCM, much as would have been done in a formal ASC review proceeding.

Second, the Contract System Costs from the 2004 base year ASCs were escalated to forecast Contract System Costs for 2007-2008 plus the four subsequent years for purposes of the section 7(b)(2) rate test. These prospective ASCs were forecast using the ASC Forecast Model. The same ASC Forecast Model was used in the WP-07 Final Proposal and the Supplemental Proposal. The model is discussed in the Final WP-07 WPRDS, WP-07-FS-BPA-05, Sections 2.19.5 through 2.19.7.

9.1.1 Data Correction for the 2004 Base Year ASC Determination

The revisions to the WP-07 Final Proposal ASC forecasts for 2007-2008 were limited to error corrections in four areas: (1) data entry errors; (2) PacifiCorp's state allocation factors; (3) functionalization codes; and (4) Contract System Load and REP load forecasts.

9.1.1.1 Input Data Corrections in the 2004 Base Year ASC Calculation

Data errors were corrected by using the electronic download and transfer to populate the ASC Cookbook. This provided the FERC Form 1 data for each of the IOUs. The ASC Cookbook was revised to include a template that is designed to facilitate the transfer of data from the FERC electronic system. The corrections to the forecast did not include changes to assumptions or functionalization that were made and discussed in Chapter 7 of this Lookback Study.

9.1.1.2 Correction of Errors to the PacifiCorp State Allocation Factors

Errors were corrected in PacifiCorp's 2004 base year ASC that resulted from data input errors. The Jurisdictional Cost Allocation Protocol (JCAP) is the procedure developed by PacifiCorp, its state commissions, and other interested parties to allocate the non-directly assignable revenues, expenses, and plant to PacifiCorp's jurisdictions. It is a listing of the allocation factors for various items in the FERC Form 1 and other items included in state commission rate orders.

The allocation factors determine how assets, liabilities, costs, and revenues are to be allocated among the multiple states for purposes of calculating PacifiCorp's revenue requirement and setting retail rates. The allocation factors are also used to prepare annual or semiannual results of operations filings. For example, the allocation factors are used to allocate the capital and operating costs of the Jim Bridger generation plant among the various states. PacifiCorp provided an electronic file containing the JCAP allocation factors. This electronic file was used in coordination with PacifiCorp's 2002 Oregon Jurisdiction Results of Operation filing.

The allocation factors in the 2002 Results of Operation filing were matched to line items in PacifiCorp's 2004 base year ASC cookbook. The allocation factors were then applied to the line items in the Cookbook. In addition, specific state-related costs were allocated using PacifiCorp's 2002 Results of Operation filing to develop percentage allocations. These direct allocations included depreciation plant and expenses, taxes, and deferred assets that had sub-account descriptions that indicated a direct allocation.

9.1.1.3 Corrections to Functionalization Code Errors

Functionalization codes are the percentage factors that are applied to revenues or costs in the ASC Cookbook Model. The factor assigns the revenues or costs to production, transmission, or distribution, or to combinations thereof.

9.1.1.3.1 ASC Cookbook Model

Correct functionalization codes were assigned to each line item in the ASC Cookbook model. Some functionalization codes were not consistent with the 1984 ASCM. The corrected functionalization codes were consistently assigned to each of the IOU Cookbook models.

9.1.1.3.2 Correction of Regulatory Asset Amortization

Regulatory assets are deferrals of costs or revenues that have been incurred by a utility but have not been recovered in rates. Examples of such assets include deferred power costs and pension benefits. In the WP-07 Final Proposal, regulatory assets were functionalized based on the nature of the assets. For example, a regulatory asset related to deferred recovery of purchase power costs would have been functionalized to production. In addition, regulatory assets were assumed to be amortized over a short period of time. In the WP-07 Final Proposal, amortization costs were included for selected regulatory assets. After reviewing the FERC Form 1 Depreciation and Amortization expense schedules, it was noted there was no indication that regulatory assets were separately amortized in any of the depreciation schedules. This error was corrected by removing the regulatory amortization from the calculation of the 2004 IOU base year ASCs.

9.1.1.4 2004 Base Year ASC Correction

Data and functionalization codes were corrected to calculate the revised base year ASCs for the IOUs. Table 9.1.1 below shows the WP-07 Final Proposal 2004 base year ASCs and this Final Supplemental Proposal 2004 base year ASCs for each IOU. Tables for each IOU are available that show the calculation of the Supplemental Proposal 2004 base year ASC calculation, the WP-07 Final Proposal 2004 base year ASC calculation, and an explanation of the error corrections. *See* Lookback Documentation, WP-07-FS-BPA-8A, section 9.1.

TABLE 9.1.1
Comparison of WP-07 Final Proposal 2004 Base Year with WP-07 Supplemental Proposal 2004 Base Year

	WP-07 Final Proposal		WP-07 Supplemental Final Proposal	
	ASC (\$/MWh)	Exch. Load (MWh)	ASC (\$/MWh)	Exch. Load (MWh)
Avista	43.01	3,510,227	43.13	3,510,227
Idaho Power	38.67	6,135,452	35.39	6,660,452
NorthWestern Energy	58.08	859,453	56.30	836,111
PacifiCorp (PNW)	40.21	10,058,325	39.12	8,767,857
Portland General	47.32	7,633,624	44.80	7,716,910
Puget Sound	48.41	10,058,203	44.73	11,066,787

2004 base year calculation included adjustments for the costs and loads associated with NLSL. The ASC forecast model adjusted the cost of serving NLSL with the annual inflation escalator. The loads associated with the NLSL were held constant. The NLSL data taken from the NLSL reports and tables can be found at the end of the Lookback Documentation, WP-07-FS-BPA-08C.

9.1.1.5 Load Forecast Corrections

In the WP-07 Final Proposal, it was incorrectly assumed that internal BPA-generated forecasts of total retail load for the IOUs did not include distribution losses. The 1984 ASCM specifies that Contract System Load includes distribution losses. Therefore, total retail load forecasts were increased by a 5 percent distribution loss factor to determine Contract System Load. It was subsequently determined that the total retail load forecasts included a 7 percent distribution loss factor; thus the WP-07 Final Proposal, in fact, overstated Contract System Load by using a 12 percent loss factor.

For this Supplemental Final Proposal, the load forecast was corrected by the following: First, the total retail load forecast was multiplied by 93 percent to eliminate the 7 percent distribution loss. This restated the load forecast to the end-use level without distribution losses. Then a 5 percent distribution loss factor was applied to increase the loads for use as Contract System Load.

Table 9.1.2 restates the ASCs and now includes the Contract System Load (CSL) forecasts for the WP-07 Final Proposal and this Supplemental Final Proposal.

TABLE 9.1.2
Comparison of WP-07 Final Proposal 2004 Base Year with WP-07 Supplemental Final Proposal 2004 Base Year

	WP-07 Final Proposal		WP-07 Supplemental Final Proposal	
	ASC ($/MWh)	CSL (MWh)	ASC ($/MWh)	CSL (MWh)
Avista	43.01	8,795,447	43.13	8,777,612
Idaho Power	38.67	13,901,568	35.39	13,533,648
NorthWestern Energy	58.08	6,862,353	56.30	6,862,353
PacifiCorp (PNW)	40.21	22,561,484	39.12	21,479,607
Portland General	47.32	18,652,345	44.80	18,422,742
Puget Sound	48.41	20,870,630	44.73	20,870,630

9.1.2 2007-2013 ASC Forecasts

Tables 9.1.3 and 9.1.4 below compare the 2007-2008 ASCs developed in the WP-07 Final Proposal with the revised 2007-2013 ASCs for this Final Supplemental Proposal. The Final Supplemental Proposal 2007-2013 ASC Models are shown in WP-07-FS-08A, Tables 9.1.6.1 through 9.1.6.6.

TABLE 9.1.3
Comparison of WP-07 Final Proposal 2007-2008 Residential Exchange Loads with WP-07 Supplemental Final Proposal 2007-2008 Residential Exchange Loads

	WP-07 Final Proposal		WP-07 Supplemental Final Proposal	
	2007 (MWh)	2008 (MWh)	2007 (MWh)	2008 (MWh)
Avista	4,085,388	4,184,196	3,824,029	3,897,357
Idaho Power	7,234,428	7,401,546	7,218,346	7,380,466
NorthWestern Energy	982,688	1,010,998	951,068	961,972
PacifiCorp (PNW)	10,644,572	10,776,134	9,168,719	9,281,739
Portland General	9,242,122	9,484,296	8,286,384	8,377,545
Puget Sound	11,189,178	11,215,422	11,746,838	11,894,349

TABLE 9.1.4
Final Supplemental Proposal
Revised 2004-2013 ASC Forecasts

	Avista		Idaho Power	
	ASC ($/MWh)	Exch. Load (MWh)	ASC ($/MWh)	Exch. Load (MWh)
2004	43.13	3,510,227	35.38	6,660,452
2005	43.03	3,590,509	35.24	6,538,585
2006	44.06	3,756,579	36.93	7,038,389
2007	45.36	3,824,029	38.26	7,218,346
2008	47.01	3,897,357	39.61	7,380,466
2009	48.00	3,981,477	40.57	7,543,106
2010	48.95	4,064,974	41.59	7,707,308
2011	50.06	4,146,629	42.71	7,884,371
2012	51.31	4,218,112	43.82	8,030,291
2013	52.57	4,263,887	44.85	8,099,305

	NorthWestern		PacifiCorp (PNW)	
	ASC ($/MWh)	Exch. Load (MWh)	ASC ($/MWh)	Exch. Load (MWh)
2004	56.30	836,111	37.12	8,767,857
2005	53.86	847,092	32.53	8,960,693
2006	54.95	898,218	33.95	9,251,568
2007	56.50	951,068	35.61	9,463,011
2008	59.18	961,972	37.45	9,579,971
2009	60.53	965,929	38.29	9,658,348
2010	61.73	974,699	39.05	9,762,851
2011	63.08	982,866	39.94	9,875,253
2012	64.39	994,162	40.98	10,033,223
2013	65.76	999,297	42.04	10,188,763

	Portland General		Puget Sound	
	ASC ($/MWh)	Exch. Load (MWh)	ASC ($/MWh)	Exch. Load (MWh)
2004	44.80	7,716,910	44.73	11,066,787
2005	44.18	7,766,126	45.62	11,382,320
2006	45.45	8,049,271	46.61	11,674,554
2007	47.55	8,286,384	47.58	11,746,838
2008	50.10	8,377,545	48.60	11,894,349
2009	51.13	8,469,639	49.53	12,057,336
2010	51.87	8,562,004	50.51	12,214,852
2011	52.84	8,651,356	51.65	12,365,385
2012	54.14	8,788,009	52.89	12,477,488
2013	55.49	8,868,995	54.16	12,586,358

9.2 Cost Allocation and Rate Design Implementation

9.2.1 Ratemaking Sequence

The ratemaking sequence used in the FY 2007-2008 Lookback is the same as was used in the WP-07 Final Proposal, except that the Subscription Strategy section is no longer necessary. The FY 2007-2008 Lookback ratemaking includes a COSA and a series of Rate Design Step adjustments using the same RAM2007 model used in the WP-07 Final Proposal. This model provides a determination of rates for the FY 2007-2008 time period. In an additional table, developed for this Lookback Study, the PF Exchange rate and a backcast of exchanging utilities' average system costs are then used to calculate the level of IOU REP benefits for FY 2007 and FY 2008.

BPA's WP-07 reformed ratemaking methodology includes a COSA, a series of Rate Design Step adjustments, and a Slice Product Separation Step. The COSA assigns responsibility for BPA's generation revenue requirement to the various classes of service in accordance with generally accepted ratemaking principles and in compliance with statutory directives governing BPA's ratemaking. The Rate Design Step adjustments to the allocated costs derived in the COSA are necessary to ensure that BPA recovers its test period revenue requirement while following its statutory rate directives. The Slice Product Separation Step separates out the PF Slice product firm loads, allocated costs, and allocated revenue credits from the overall non-Slice PF loads, allocated costs, and allocated revenue credits. This ratemaking sequence is programmed into a spreadsheet model, RAM2007, for purposes of calculating BPA's requirements power rates.

9.2.2 Cost of Service Analysis (COSA)

The COSA allocates the test period generation revenue requirement to BPA customer classes determined in the Final Revenue Requirement Study, WP-07-FS-BPA-02, without revisions. The COSA apportions or "allocates" the test period generation revenue requirement among classes of service based on the principles of cost causation. The relative use of resources, services, or facilities among customer classes is identified, and costs are generally allocated to customer classes in proportion to each class's use. Cost allocation also is based on the priorities of service from resource pools to rate pools provided in section 7 of the Northwest Power Act.

BPA uses three major ratemaking steps to complete the process of determining BPA's total cost of service for power rates: (1) *functionalization* of costs between generation and transmission to develop the generation revenue requirement; (2) *classification* of costs between demand, energy, and load variance; and (3) *allocation* of costs to classes of service.

In the Lookback for FY 2007-08, the PF Exchange power rate is recalculated using REP costs in place of the REP settlement costs. Functionalization of costs between generation and transmission is performed in conjunction with the development of BPA's total revenue requirements, and only those costs assigned to the Power function are included in the revenue requirement. The one exception is for gross exchange resource costs. These costs are functionalized between generation and transmission in the model so that only the power generation portion is subject to the power cost rate design steps; the costs functionalized to transmission are then reincorporated after the rate design steps are completed. The remaining steps to determine BPA's cost of service for wholesale power – classification and allocation of costs – are performed in the COSA portion of the WPRDS. *See* Lookback Documentation, WP-07-FS-BPA-08A, section 9.2.

9.2.3 Power Revenue Requirement

The Bonneville Project Act, the Flood Control Act of 1944, the Transmission System Act, and the Northwest Power Act provide guidance regarding BPA ratemaking. The Northwest Power Act requires BPA to set rates that are sufficient to recover, in accordance with sound business principles, the cost of acquiring, conserving, and transmitting electric power, including amortization of the Federal investment in the FCRPS over a reasonable period of years, and the other costs and expenses incurred by the Administrator. 16 U.S.C. § 839e(a)(1).

The Final Revenue Requirement Study, WP-07-FS-BPA-02, is based on generation revenue and cost estimates for a three-year test period, FY 2007-2009. The revenue requirement from the Revenue Requirement Study is adjusted in the COSA for projected balancing purchase power costs, system augmentation costs, and the gross REP costs functionalized to power. The adjusted annual Power function revenue requirements used for rate calculations are shown in the WPRDS. *See* Lookback Documentation, WP-07-FS-BPA-08A, Tables 9.2.3.1 (COSA 06 FY 2007) through 9.2.3.3 (COSA 06 FY 2009). The functionalization of the gross REP costs is shown in the Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.4 (COSA 07). The total adjusted functionalized revenue requirements for the three-year period are shown in the Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.5 (COSA 08).

9.2.3.1 Revenue Requirement Study

In compliance with a FERC order, BPA has prepared a power repayment study specifically for the generation function. *See U.S. Department of Energy – Bonneville Power Admin.*, 26 FERC ¶61,096 (January 27, 1984). All costs functionalized to generation are used to develop the generation revenue requirement, which is recovered through FCRPS power rates.

The Final Revenue Requirement Study, WP-07-FS-BPA-02, also includes demonstrations to show that revenue from the proposed rates is adequate to recover all generation-related costs of the FCRPS in the rate period and over the repayment period (revised revenue test).

9.2.3.2 Power Purchases in the COSA

Three categories of purchased power are included in the COSA. These are: (1) purchased power; (2) balancing power purchases; and (3) system augmentation. Gross REP costs, while portrayed in section 5(c) of the Northwest Power Act as a purchase of power by BPA, are not included in the categories.

9.2.3.2.1 Purchased Power

The purchased power costs reflect the acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs. Costs of purchased power are included in the new resources resource pool. *See* Lookback Documentation, WP-07-FS-BPA-08A, Tables 9.2.3.1, 9.2.3.2, and 9.2.3.3 (COSA 06 for FY 2007-2009).

9.2.3.2.2 Balancing Power Purchases

The costs of power purchases and storage required to meet firm deficits on a less-than-annual basis are included in the category of balancing power purchases. Projected balancing power purchases are needed to serve firm loads in months other than the spring fish migration period under some water conditions. The value that is used in the revenue requirement is the expected value over 50 water year conditions. This balancing power purchase expense estimate is developed in the Risk Analysis Study (using RiskMod) to reflect projected operation of the FCRPS. *See* Final Risk Analysis Study, WP-07-FS-BPA-04. For this Lookback analysis for FY 2007-2008, the balancing purchase amounts have not been changed from those in the WP-07 Final Proposal. *See* Final WPRDS Documentation, WP-07-FS-BPA-05A, section 3.4. Costs of balancing power purchases are characterized as FBS replacements and, as such, are included in – and allocated as – FBS costs. *See* Lookback Documentation, WP-07-FS-BPA-08A, Tables 9.2.3.1, 9.2.3.2, and 9.2.3.3 (COSA 06) for FY 2007-2009.

9.2.3.2.3 System Augmentation

BPA also has need to acquire annual amounts of power beyond the inventory represented by the FCRPS and balancing power purchases. These acquisitions are defined as system augmentation and are used to meet customer firm power loads in excess of firm system resources on an annual basis. System augmentation purchases are characterized as FBS replacements and are allocated as FBS costs. For this Lookback analysis for FY 2007-2008, the system augmentation purchases amounts have not been changed from those in the WP-07 Final Proposal. System augmentation costs are shown in the Lookback Documentation, WP-07-FS-BPA-08A, Tables 9.2.3.1, 9.2.3.2, and 9.2.3.3 (COSA 06) for FY 2007-2009.

9.2.4 Functionalization of Residential Exchange Program Costs

In the COSA, the gross REP cost is based on exchanging utilities' ASCs and the amount of their exchange loads. ASCs include the resource costs associated with serving an exchanging utility's load. The 1984 ASCM specifies what constitutes resource costs, but simply stated, they include most power costs and certain transmission costs. Since the ASCs include transmission costs, the gross costs of the exchange include transmission costs. Therefore, some of the gross costs of the exchange are functionalized to transmission. The rate design adjustments that follow the COSA in BPA's ratemaking sequence use the results of the COSA on the revenue requirement that has been functionalized to power. Therefore, because the REP cost that is used in the COSA includes energy costs, demand costs, and transmission costs, these costs are functionalized between generation and transmission. The REP costs functionalized to generation continue through the ratemaking process, and the REP cost functionalized to transmission are added to the PF Exchange rate after all the rate design steps have been accomplished. In this way, the REP costs functionalized to generation are treated the same as other Power function costs as they go through the rate design adjustment process. The functionalization of REP costs is shown in the Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.4 (COSA 07).

9.2.5 Classification

Classification in the WPRDS apportions generation costs between the demand, energy, and load variance components of electric power. This classification of the generation revenue requirement is shown in the Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.5 (COSA 08).

The classification methodology BPA uses is generally based on the marginal costs of the components of power and generally accepted ratemaking procedures. In this rate filing, the Demand Rate is based on a Partial Resolution of Issues, as it was in the WP-07 Final Proposal. A description of the Demand Rate methodology is in section 2.2.1.2.1 of the WP-07 WPRDS, WP-07-E-BPA-05A. In addition, BPA estimates the Load Variance Rate using market prices. *See* section 2.2.4.1 of the WP-07 WPRDS, WP-07-E-BPA-05A, for a detailed description. The Load Variance Rate is scaled in accordance with the Partial Resolution of Issues. Sales and revenues of these products are then forecast. Revenue forecasts associated with demand are deemed equal to the cost of and classified to demand. Revenues forecast for Load Variance are deemed to be equal to the cost of Load Variance and are classified as such. Generation costs classified to energy are the residual total generation costs not classified to demand or load variance. BPA continues this classification scheme in this Supplemental Proposal; however the costs of demand and load variance are now directly allocated to customer rate pools along with the costs of energy. After all allocation and rate design steps, the costs of demand and load variance are subtracted from the overall costs allocated to each rate pool, and the energy rates are adjusted to collect the remainder.

9.2.6 Functionalized and Classified Revenue Credits

The revenue credits described here are functionalized to generation and classified to energy. Most of these revenue credits are associated with the operation of FBS resources and have the effect of reducing the FBS resource costs to be recovered by BPA's power rates.

9.2.6.1 Downstream Benefits and Pumping Power Revenues

Downstream benefits and pumping power revenues are payments from the sale of Reserve Energy, irrigation pumping power, and revenue from owners of projects downstream to the Corps and Reclamation for benefits received (*i.e.*, additional generation) from the storage reservoirs owned by the Corps and Reclamation. Reserve energy and irrigation pumping power revenue is earned through the year, and paid at the end of the year directly to the Treasury by the Corps and by Reclamation. These revenues are not subject to revision through BPA's rate processes and hence become a revenue credit. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.6.2 Section 4(h)(10)(C) Credits

Section 4(h)(10)(C) credits are available from the Treasury to compensate BPA for its direct program fish and wildlife expense and capital costs and hydro system operation costs incurred for fish migration attributable to the non-power portions of the hydro projects. These credits are 22 percent of these costs. This revenue credit is an estimate of what BPA would receive on average over a range of 50 different water conditions. The actual credit is determined after each year is complete. The operation costs vary with water conditions. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.6.3 Colville Credit

The Colville credit is a Treasury credit BPA receives as a result of a settlement of claims associated with the development of Grand Coulee Dam. The credit is a predetermined amount fixed by legislation. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.6.4 Energy Efficiency Revenues

This credit is for reimbursable expenses arising from the activities of BPA's Energy Services Business. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.6.5 Miscellaneous Revenues

This credit represents estimated revenues from contract administration, late fees, interest on late payments, and mitigation payments. These fees are not subject to changes in BPA's ratemaking processes. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.6.6 Reserve Product Revenues

Reserve product revenues result from the sale of products and services provided under the FPS rate schedule to customers outside the BPA Control Area and may include supplemental automatic generation control, spinning reserves, supplemental reserves, and forced outage reserves. See Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.6.7 Green Tag Revenues

Green energy premiums (GEPs) result from BPA sales of Environmentally Preferred Power (EPP) and renewable energy certificates (REC). The revenues depend on actual wind and renewable project output included in the FCRPS. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.6.8 Power Services Ancillary and Reserve Services Revenues Credits

Power Services, in the course of marketing power, generates transmission-related revenues and credits. The revenues and credits are predominantly revenues associated with providing ancillary and reserve services from the FCRPS. *See* section 4 of the Final WPRDS, WP-07-FS-BPA-05A. The revenues and credits are classified to energy and are used reduce the FBS resource costs to be recovered by BPA's power rates. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.7 Allocation

Allocation is the apportionment of costs to customer classes. Allocation is performed by determining the relative sizes of resource pools and rate pools pursuant to the rate directives contained in section 7 of the Northwest Power Act. Rate pools are groupings of customer classes (sales or loads) for cost allocation purposes. BPA groups its loads into the "Priority Firm," "Industrial Firm," and "All Other" categories corresponding to sections 7(b), 7(c), and 7(f) of the Northwest Power Act. The resource pools are those identified in the Northwest Power Act as the FBS, REP, and new resources resource pools. Costs associated with each of these respective resource pools are grouped together to facilitate allocation. The sizes of the rate and resource pools are determined from forecast load and resources presented in the Final Load Resource Study, WP-07-FS-BPA-01.

The Northwest Power Act established three rate pools. The 7(b) rate pool includes public body and cooperative (collectively, COUs) and Federal agency sales under section 5(b) of the Northwest Power Act, as well as the sales to utilities participating in the REP established in section 5(c) of the Northwest Power Act. The 7(c) rate pool includes sales to BPA's DSI customers under section 5(d) of the Northwest Power Act. The 7(f) rate pool includes all power BPA sells under section 5(f) of the Northwest Power Act. Subsequent to 1985, with the implementation of the directives of section 7(c)(2) of the Northwest Power Act, BPA has had, for all practical purposes, only two rate pools: the 7(b) rate pool and all other loads.

In the Lookback Study, the FBS resource pool consists of the following resources: (1) the FCRPS hydroelectric projects; (2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and (3) replacements for reductions in the capability of the above resource types. Costs expected to be incurred during the rate period for replacement resources were included in the FBS resource pool. *See* Final Revenue Requirement Study Documentation, WP-07-FS-BPA-02A. In addition to long-term resource acquisitions, short-term power purchases are made during the rate period. These short-term power purchases augment the Federal system to achieve load/resource balance on an annual basis as well as balance the Federal system to provide operational flexibility and provide for certain fish mitigation measures on a monthly and daily basis. The costs of such balancing purchases, as well as the cost of system augmentation to ensure load/resource balance, are considered to be FBS costs and are allocated as such.

9.2.7.1 Power Cost Allocations

The process for allocating power costs begins with an examination of critical period firm loads and resources. A ratemaking load and resource balance for each year of the test period is then constructed from the Final Load Resource Study, WP-07-FS-BPA-01, and other data. From this ratemaking load and resource balance, service to each of the three rate pools from each of the resource pools is determined for the rate test period. Table 9.2.4.1 (ALLOCATE 01) shows the ratemaking energy loads and resources by pools. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.4.1 (ALLOCATE 01).

9.2.7.2 Energy Allocation Factors

When service from each resource pool to each class of service has been identified, the amounts of such service are the allocation factors for the costs of the resource pool. Resource pool costs are allocated to classes of service based on the proportions of their identified use of the resource pools to the total size (use) of the resource pool. The annual energy allocation factors for each resource pool are shown in the Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.4.1 (ALLOCATE 01). The Total Usage and Conservation allocation factors are the same and are based on the sum of the FBS, REP, and new resources allocation factors. They are used to allocate costs and rate design adjustments to all firm energy loads. Because BPA had no load forecast under the IP and NR classes of service, a very small amount of load, 0.001 aMW, was used as a token IP and NR load for ratemaking purposes. The energy allocation factors associated with these very small loads allow the proper ratemaking sequence to be used to calculate an IP and NR rate while allocating a negligible amount of real costs to these token loads. Allocated power costs are shown in the Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.4.2 (ALLOCATE 02).

9.2.7.3 Other Cost Allocations

Costs not directly identifiable with rate pools, resource pools, or transmission costs allocated to Power Services (PS) are allocated as described in the following sections.

9.2.7.3.1 Conservation Costs

The Northwest Power Act requires BPA to treat cost-effective conservation as an electric power resource in planning to meet the Administrator's obligations to serve loads. 16 U.S.C. § 839a1(a). The "conservation" line item, as seen in the COSA 06 tables (*see* Lookback Documentation, WP-07-FS-BPA-08A, Tables 9.2.3.1, 9.2.3.2, and 9.2.3.3), includes: (1) debt service for BPA's previous resource acquisition activities; (2) BPA's continuing contributions to the region's market transformation efforts; (3) costs associated with BPA's energy efficiency business; (4) costs associated with the Conservation Rate Credit; and (5) a share of the agency's total planned net revenues. The "Energy Efficiency" revenue line item seen in Table 9.2.3.6 (COSA 09) reflects payments provided by other BPA organizations and Federal agencies for the energy efficiency services delivered. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.6 (COSA 09).

9.2.7.3.2 BPA Program Costs

Some of BPA's program costs are not identified directly with any specific resource pool or customer class. An example is the cost of the ratemaking process. The generation portion of these program costs is determined in the Final Revenue Requirement Study, WP-07-FS-BPA-02. The generation portion appears as BPA program costs. These program costs, as seen in Table 9.2.3.5 (COSA 08) are allocated uniformly to all customer classes based on the total usage allocation factors for energy. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.3.5 (COSA 08).

9.2.7.3.3 Planned Net Revenues for Risk

PNRR is the amount of net revenues required from power rates to ensure that cash flows from proposed rates fully meet BPA's probability standard for repaying Power Service's portion of Treasury payments on time and in full. PNRR are allocated to resource pools that include

Federal capital investments. The methodology for allocating these costs is described and illustrated in the Final Revenue Requirement Study Documentation, WP-07-FS-BPA-02A, section 2.

The PNRR value found in the COSA 06 tables is the result of an iterative process between the RAM2007, the RiskMod, NORM, and the ToolKit models. *See* Final Risk Analysis Study, WP-07-FS-BPA-04. The iteration is initiated with a seed value for PNRR in COSA 06 of the RAM2007. The resultant rates are used in RiskMod to produce probability distributions. These distributions are then used in the ToolKit to produce a new PNRR value for new COSA 06 tables. For this FY 2007-2008 Lookback analysis, the PNRR amounts have not been changed from those in the WP-07 Final Proposal and no iterative process was conducted. For further explanation of this iterative process, *see* Doubleday, *et al.*, WP-07-E-BPA-15.

9.2.8 COSA Results

The COSA results are allocated to the test period revenue requirements for power to classes of service served with firm power. Table 9.2.4.2 (ALLOCATE 02) summarizes the allocated generation power revenue requirement and the total allocated revenue requirement recovered from power classes of service. This includes transmission costs allocated to the Power function. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.4.2 (ALLOCATE 02).

9.3 Rate Design Step Adjustments

Rate design adjustments are performed sequentially in the order described in the following section.

9.3.1 Secondary and Other Revenue

Secondary and Other Revenue recognizes that BPA collects revenues from certain classes of service to which costs are not allocated, and then credits these revenues to classes of service served with firm power. Projected secondary energy sales are the largest source of revenue credits.

9.3.1.1 Secondary Energy Sales

On a resource planning basis and with system augmentation, BPA forecasts sufficient firm resources available to meet firm load obligations under critical water conditions. However, rates are set assuming that better-than-critical water conditions will occur. For this FY 2007-2008 Lookback analysis, the secondary energy sales are assumed to be the same as in the WP-07 Final Proposal. BPA projects secondary energy sales and revenues using 50 historical water years as determined in RiskMod. *See* Normandeau, *et al.*, WP-07-E-BPA-14. The projected secondary energy revenue credits are allocated to firm loads so that BPA does not recover more than its revenue requirement.

The RiskMod model is used to project the level of secondary energy sales and revenues. BPA expects to sell secondary energy that will produce $1.749 billion in revenues over the three-year rate period. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.3 (RDS 11).

9.3.1.2 Other Revenue Credits

BPA sells firm power under FBS contract obligations and in the open market under the FPS rate schedule. For this FY 2007-2008 Lookback analysis, the other revenue credits are assumed to be the same as in the WP-07 Final Proposal. For FY 2007-2009, the forecast revenue from these sales is $555.7 million. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.3 (RDS 11).

9.3.1.3 Allocation of Secondary Revenue Credits

Secondary Revenue credits are functionalized to generation and classified to energy. They are then allocated to loads served with Federal system resources (FBS and new resources). The generation-related revenues are allocated in this manner because they are associated with the use of Federal system resources to serve the firm contract sales and the secondary energy service. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.3 (RDS 11).

9.3.2 Firm Power Revenue Deficiencies Adjustment

BPA sells firm power at contractual rates and in the open market under the FPS rate schedule. Sales of such firm power are not necessarily made at the fully allocated costs of the power. Therefore, either a revenue surplus or a revenue deficiency will result when a comparison is made between the costs allocated to the firm power and the revenues received from the sale of such power. BPA has determined that in the FY 2007-2009 rate period, it will receive $342.7 million in revenues from the sale of firm power in various PNW and Southwest markets. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.4 (RDS 17). BPA has allocated $1.965 billion in generation costs to the firm power sold. BPA has allocated no revenue credits to the firm power sold. Therefore, there is a revenue deficiency of $1.622 billion over the three-year rate period. This revenue deficiency is charged to all firm power (PF, IP, NR) customers. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.4 (RDS 17) and Table 9.2.5.5 (RDS 19).

Before the inter-rate-pool rate adjustments are made, an initial allocation to rate pools summary that includes the COSA results, the allocation of secondary and other revenue credits, the allocation of FPS contract and FBS obligation contract revenue deficiencies is conducted. In addition, to recognize that BPA's Low Density Discount (LDD) and Irrigation Rate Mitigation Product (IRMP) will lower the revenues collected through PF Preference rate sales, an estimate of the lost revenue is added to the costs allocated to the PF rate pool. This initial allocation of costs to the individual rate pools is the starting position for the ensuing rate adjustments. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.5 (RDS 19).

9.3.3 7(c)(2) Adjustment

DSI rates are based on sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. Section 7(c)(1)(B) provides that after July 1, 1985, the DSI rates will be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Pursuant to section 7(c)(2), the DSI rates are to be based on BPA's "applicable wholesale rates" to its preference customers plus the "typical margins" included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rates are also to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) credit. To more accurately reflect the product Power Services may purchase from the DSI customers, the name has been changed to Supplemental Contingency Reserve Adjustment (SCRA). However, for this rate case, BPA is not proposing a uniform SCRA credit to be applied against DSI rates. *See* Final WPRDS, WP-07-FS-BPA-05, Appendix B. Thus, the DSI rates are set equal to the applicable wholesale rate, plus the typical margin, subject to the DSI floor rate test and the outcome of the section 7(b)(2) rate test. *See* Sections 9.3.4 and 9.3.5.

The applicable wholesale rate is the PF rate (in combination with the NR rate if new NLSLs were projected for the test period) at the DSI load factor. The typical margin is based generally on certain overhead costs that preference customers add to BPA's price of power in setting their retail industrial rates. The methods and calculations used to determine the typical margin are discussed in detail in the Final WPRDS, WP-07-FS-BPA-05, Appendix A. The net margin is

0.573 mills/kWh and has not been changed from the original WP-07 Final Proposal. As previously stated, a zero SCRA credit is being forecast in this rate case. This net margin is added to the seasonal and diurnal PF Energy rates. These adjusted PF Energy rates and the rate for demand are applied to the DSI test period billing determinants to determine the preliminary IP rate.

The section 7(c)(2) adjustment is necessary to account for the difference between the revenues BPA expects to recover from the DSIs at the initial IP rate and the costs allocated to the DSIs. This difference, known as the 7(c)(2) delta, is allocated to non-DSI customers, primarily the PF customers. Because the allocation of the 7(c)(2) delta changes the PF rate upon which the IP rate is based, the entire process is repeated with the revised PF rate from the previous iteration until the size of the 7(c)(2) delta does not change when a successive iteration is performed. This process has been reduced to an algebraic solution. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.6 (RDS 21).

BPA did not sell power under the IP rate schedule for this Lookback period. Therefore, the size of the 7(c)(2) delta for the Lookback period is inconsequential for ratemaking purposes. However, the calculation is shown for continuity of methodology purposes.

9.3.4 7(b)(2) Adjustment

The rate test specified in section 7(b)(2) of the Northwest Power Act ensures that BPA's public body, cooperative, and Federal agency customers' firm power rates applied to their requirements loads are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. If the section 7(b)(2) rate test triggers, the public body, cooperative, and Federal agency customers are entitled to rate protection. The cost of this rate protection is borne by other purchasers of firm power. In order to make these cost adjustments, the PF rate is bifurcated. The two resulting rates are the PF Preference rate, which receives the rate protection, and the PF Exchange rate, which pays, at least in part, the cost of the rate protection.

The Lookback Section 7(b)(2) Rate Test Study, Chapter 10, indicates the section 7(b)(2) rate test has triggered and the PF rate applicable to BPA's preference customers should be adjusted downward. The amount of downward adjustment needed is implemented through a reduction of the PF Preference rate. Historically, it is at this point in the ratemaking process that BPA makes three adjustments in the rate design sequence to provide this protection to its preference customers and allocate the costs of the rate protection.

First, the PF Preference customer class is given a credit, which reduces its rate by the amount of the protection indicated in the section 7(b)(2) rate test. The 3.4 mills/kWh rate test trigger results in a protection amount of $624.7 million to PF Preference customers. The cost of providing this protection is allocated to the remaining firm power customers (PF Exchange, IP, and NR). *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.9 (RDS 30).

The second adjustment is the 7(b)(2) Industrial Adjustment. The amount of this adjustment is the value of a recalculated 7(c)(2) delta at the lower PF Preference rate. Because there is no IP load forecast for this rate period, a very small token IP load of 0.001 aMW is used in ratemaking; therefore, the amount of the new 7(c)(2) delta is close to zero. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.10 (RDS 33).

In this Lookback analysis, there was no exchanging utility in deemer status. If there had been, a third adjustment would have been necessary to allocate an increase in the gross REP costs resulting from the bifurcation of the PF rate, causing the PF Exchange rate to be higher than the average combined rate before the bifurcation. This process is explained in the Supplemental WPRDS, WP-07-FS-BPA-13, section 3.3.6.

9.3.5 DSI Floor Rate Test

Section 7(c)(2) of the Northwest Power Act requires that the DSI rates in the post-1985 period "shall in no event be less than the rates in effect for the contract year ending June 30, 1985." Accordingly, a floor rate test is performed to determine if the proposed IP rate has been set at a level below the 1985 IP rate (the floor rate). If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers with the increased revenue from the DSIs. If the proposed IP rate has been set at a level above the floor rate, no floor rate adjustment is necessary. Because the Lookback IP rate revenues are greater than the floor rate revenues, no adjustment was necessary to the IP rate. *See* Lookback Documentation, WP-07-FS-BPA-08A, Tables 9.2.5.7 and 9.2.5.8. With no DSI floor adjustment required, the final Rate Design Step allocations are shown in the Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.5.10 (RDS 33).

9.3.6 Slice Cost Calculation

Slice customers assume the obligation to pay a percentage of BPA's costs, rather than pay a set rate per kilowatt or kilowatt-hour. The Slice customer's obligation to pay is equal to the percentage of the FCRPS that the Slice customer elects to purchase. The costs considered by the Slice contract are referred to collectively as the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's Power function revenue requirement identified in this rate case, with certain limited exceptions. For the calculation of the cost of the Slice product in dollars per month for each percent of the Federal system, *see* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.13 (Slice Cost).

9.3.7 Slice PF Product Separation Step

In the COSA and Rate Design steps, costs were allocated to the various rate pools, including the PF Preference class of service that contained all firm PF Preference load. The Slice Separation

Step separates out the PF Slice product revenues, firm loads, and revenue credits from the overall PF Preference rate pool, leaving the costs that must be covered by the remaining non-Slice PF Preference load through posted PF Preference energy, demand, and load variance charges. *See* Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.6 (SLICESEP 01).

9.3.8 Rate Analysis Results

In this FY 2007-08 Lookback portion of the Supplemental Proposal, BPA recalculated the FY 2007-2008 PF Exchange rate using the costs of a traditional REP in place of the costs of the REP settlements. The rate modeling described above resulted in an average PF Preference rate of 24.77 mills/kWh and a PF Exchange rate of 42.51 mills/kWh. This PF Exchange rate, when applied to the backcast ASCs, produced net REP benefits averaging $237 million per year for FY 2007 and FY 2008. *See* Table 14.2 in this Study and Lookback Documentation, WP-07-FS-BPA-08A, Table 9.2.7, Table 9.2.8, and Table 9.2.9.

9.4 Slice of the System (Slice) Product, Slice Revenue Requirement, and Slice Rate

9.4.1 Explanation of Changes

This chapter reflects changes to the Slice True-Up process and the treatment of certain expenses and revenue credits due to the Slice Mediation Settlement Agreement (Slice Settlement), which was signed and executed by BPA, the Slice customers, and the Northwest Requirements Utilities on November 22, 2006. In addition, this chapter reflects the impact on the Slice Revenue Requirement that resulted from decisions by the Ninth Circuit regarding the 2000 REP Settlement Agreements (REP Settlement Agreements).

9.4.2 Slice Product Description

The Slice product is a sale of a fixed percentage of the generation output of the Federal Columbia River Power System (FCRPS). It is not a sale or lease of any part of the ownership of, or operational rights to, the FCRPS. The Slice product is a power sale based upon a Slice customer's annual firm net requirement load and is shaped to BPA's generation output from the FCRPS. BPA's sale of the Slice product required a commitment by each Slice customer to purchase the product for 10 years, from FY 2002 through FY 2011.

Because the Slice product is calculated as a percentage of the FCRPS generation output, the actual amount of power delivered to the Slice customer varies throughout the year. During certain periods of the year and under certain water conditions, the power delivered exceeds the Slice customer's firm net requirement and may, at times, exceed the Slice customer's actual firm load. As a consequence, the Slice product entails a sale of both requirements power and surplus power.

9.4.3 Slice Revenue Requirement

Each Slice customer pays a percentage of BPA's costs, rather than a set price per megawatt and megawatt hour. The Slice customer's obligation to pay is based on the percentage of the FCRPS generation output that the Slice customer elected to purchase in its 10-year Subscription contract. The Slice customers pay a percentage of the Slice Revenue Requirement. The Slice Revenue Requirement is comprised of all of the line items in BPA's power revenue requirement, with certain limited exceptions. See Table 9.4.1, Slice Product Costing and True-Up Table for a detailed list of the line items and forecasted dollar amounts in the Slice Revenue Requirement). In 2003, BPA engaged in litigation before the Ninth Circuit concerning the appropriate interpretation and implementation of the Slice rate and the Slice Rate Methodology. *Northwest Requirements Utilities, et al. v. Bonneville Power Administration*, No. 03-73849, *Northwest*

Requirements Utilities v. Bonneville Power Administration, No. 04-71311, and *Benton County PUD, et al. v. Bonneville Power Administration,* No. 03-74179. In July 2006, BPA, the Slice customers, and the Northwest Requirements Utilities agreed on a settlement of the issues. The Slice Settlement (07PB-12273) was approved by the U.S. Department of Justice and was signed and executed by all parties on November 22, 2006. The Slice Settlement resolved all Slice True-Up disputes for Contract Years 2002-2005, along with previously disputed substantive issues, in a way that will have precedential effect beyond 2005. The Slice Settlement provided for refunds to Slice customers in the form of credits to their bills that settled disputes related to the Slice True-Up Adjustment Charges for FY 2002-2005. It also included a new dispute resolution provision and a Memorandum of Understanding regarding BPA's Debt Optimization Program.

In this Supplemental Final Proposal, BPA is modifying the rate treatment of certain Slice rate and Slice Rate Methodology matters, consistent with the Slice Settlement (*see* Lee, *et al.,* WP-07-E-BPA-59).

9.4.4 Inclusion and Treatment of Expenses and Revenue Credits

BPA made changes to the treatment of particular expenses and revenue credits in the Slice True-Up for FY 2007 and FY 2008, consistent with the Slice Settlement. BPA will continue this treatment for the Slice True-Up on a prospective basis.

The Slice Revenue Requirement includes the same expenses and revenue credits that are included in the Power Services revenue requirement, with certain limited exclusions. In general, there are three types of excluded expenses: (1) power purchases except those associated with the inventory solution; (2) inter-business line transmission costs except those associated with serving

BPA System Obligations and GTAs; and (3) PNRR (or its successor risk mitigation tools) and hedging expenses except those hedging expenses associated with the inventory solution. The following paragraphs clarify the rate treatment of particular items in the Slice Revenue Requirement and Actual Slice Revenue Requirement. The Slice Revenue Requirement includes all the expenses and revenue credits that are the basis for calculating the Slice rate for FY 2007-2008. The expenses and revenue credits included in the Slice Revenue Requirement that is the basis for the FY 2007-2008 Slice rate are forecasts for FY 2007-2009 that were determined in the WP-07 Final Proposal. The Actual Slice Revenue Requirement includes the same expense and revenue credit categories as the Slice Revenue Requirement, but is comprised of the final audited actual expenditures and revenues as reflected on BPA's Power Services financial statements, including any adjustments that result from this proceeding. The Actual Slice Revenue Requirement for a given fiscal year is used as the basis for the calculation of the annual Slice True-Up Adjustment Charge for that fiscal year. See Section 9.4.6, Slice True-Up, for a more detailed description of the Slice True-Up process.

9.4.4.1 Augmentation Expenses

During the prior rate period (FY 2002-2006), BPA supplemented the capability of the FBS to meet the total load placed on BPA (augmentation purchases). These augmentation power purchases were those needed to meet all load service requests made under BPA's Subscription contracts on a planning basis. Conceptually, augmentation purchases are considered to be separate and distinct from "balancing purchases." "Balancing purchases" refers to those purchases used to replace reduced hydro system flexibility due to increased operating constraints and to those purchases needed to serve BPA's load on an hourly and monthly basis. Slice customers do not pay for BPA's "balancing purchases," as the Slice customers face the risk of reduced hydro system flexibility directly and have the obligation to serve their own loads on an hourly and monthly basis.

Slice customers are required to pay their proportionate share of the net cost of all augmentation expenses. The "net cost" of augmentation refers to the costs associated with the purchase of the augmentation power less the associated revenues from the sale of such augmentation power. Slice customers do not receive any power associated with these augmentation purchases.

In the WP-07 Final Proposal, BPA forecasted that there would be augmentation expenses during the FY 2007-2009 rate period. BPA identified three distinct types of augmentation expenses in the FY 2007-2009 rate period: (1) "residual" augmentation expenses; (2) "deferred" augmentation expenses; and (3) other augmentation expenses.

"Residual" augmentation expenses are the expenses associated with augmentation purchases that carried over from the FY 2002-2006 rate period into FY 2007-2009. When BPA purchased power on the market to meet its load obligations for the FY 2002-2006 rate period, some of the purchases extended to the end of the 2006 calendar year, rather than ending at the close of the rate period (September 30, 2006). The aMWs associated with the residual augmentation purchases were needed to meet BPA's load obligation for FY 2007. Slice customers paid their proportionate share of the "net cost" of these residual augmentation purchases. For the net cost calculation, BPA assumes that it will purchase 105 aMW of residual augmentation power for a total of $49 million in FY 2007. (*See* WPRDS Documentation, WP-07-FS-BPA-05A, Table 3.6.2, at 58.) This expense ended in FY 2007.

The revenues associated with the sale of the residual augmentation power were estimated, based on the average PF rate for power and multiplied by the amount of power that would be sold, which was 105 aMW in FY 2007. The average PF rate determined in the WP-07 Final Proposal was 27.33 mills per kWh. BPA subtracted the expected revenues from the purchase expense to calculate the net cost of the residual augmentation purchases for FY 2007. The net cost of the residual augmentation purchases for FY 2007 was not subject to the Slice True-Up process.

The second type of augmentation expenses are those referred to as "deferred" augmentation. This category contains those augmentation expenses incurred during the FY 2002-2006 rate period, but the payment of which was deferred to FY 2007-2009 and beyond. The deferred augmentation expenses were associated with payment of a "Reduction of Risk Discount" to Puget Sound Energy (PSE) and PacifiCorp. The *Proposed Contracts or Amendments to Existing Contracts with the Regional Investor-Owned Utilities regarding the Payment of Residential and Small-Farm Consumer Benefits under the Residential Exchange Program Settlement Agreements FY 2007 -2011 Administrator's Record of Decision* (May 25, 2004) (IOU REP Settlement ROD) modified approximately $200 million in Reduction of Risk Discount payments to PSE and PacifiCorp. PSE and PacifiCorp agreed to forgo collection of the one-half of the Reduction of Risk Discount ($100 million) and deferred collection of the balance ($100 million) until the FY 2007-2011 period. With interest payments, this totals to $115 million of deferred augmentation expenses for FY 2007-2011, which will be recovered through PF rates in amounts of $23 million per year. (*See* Table 9.4.1, Slice Product Costing and True-Up Table.)

As the result of a series of decisions by the Ninth Circuit, BPA must make modifications to the deferred augmentation expenses.

BPA will revise this expense for FY 2009 in its WP-07 Supplemental Rate Case, but this revision will not affect the Slice Revenue Requirement for FY 2007-2009 that is the basis for the FY 2007-2008 Slice rate. In the WP-07 Final Proposal, these estimates were not subject to the annual Slice True-Up, as they were set by contract and were not expected to change. Slice customers paid their proportionate share of these deferred augmentation expenses through their Slice rate in FY 2007-2008. However, due to the Ninth Circuit ruling, these expenses were not incurred. BPA will credit Slice customers for their share of difference between the forecast deferred augmentation expense and the actual deferred augmentation expense through BPA payments to Slice customers, per the WP-07 Supplemental Final Proposal Record of Decision (WP-07 Supplemental ROD).

The third category of expenses is “other” augmentation expenses. This category includes the expenses associated with augmentation purchases that BPA needed to meet its load obligation during FY 2007-2009. In the WP-07 Final Proposal, BPA forecasted the augmentation amounts for FY 2007, 2008, and 2009 to be 179 aMW, 179 aMW, and 270 aMW, respectively. (*See* Load Resource Study, WP-07-FS-BPA-01, at 60.) Slice customers are obligated to pay their proportionate share of the “net cost” of these augmentation purchases. For the WP-07 Final Proposal, BPA assumed that it would purchase augmentation power in FY 2007 at $61.90 per MWh, in FY 2008 at $60.40 per MWh, and in FY 2009 at $62.10 per MWh. (*See* WPRDS Documentation, WP-07-FS-BPA-05A, Table 3.6.2, at 60.) The revenues associated with the sale of augmentation power were estimated, based on the projected PF rate for power, and multiplied by the amount of power that would be sold (179 aMW, 179 aMW, and 270 aMW, respectively, for FY 2007, FY 2008, and FY 2009). The projected PF rate was 27.33 mills per kWh. BPA subtracted the expected revenues from the forecast purchase expense to calculate the net cost of the augmentation purchases for FY 2007-2009 determined in the WP-07 Final Proposal. The net cost of augmentation power for FY 2007-2009 was not subject to the Slice True-Up process.

9.4.4.2 Conservation Augmentation (ConAug)

Conservation Augmentation (ConAug) was the conservation component of BPA’s inventory solution in the WP-02 rate case. ConAug was a resource acquisition effort to purchase conservation measures to reduce BPA’s load obligation.

The annual costs of ConAug were estimated and included in the augmentation expenses for the FY 2002-2006 Slice Revenue Requirement. Since it was not known specifically during the WP-02 rate case how the ConAug program would be implemented, the annual costs were derived as if the load reduction was equivalent to a power purchase. The estimate of ConAug costs was based on the assumption that 20 aMW of ConAug would be purchased each year during the FY 2002-2006 rate period. The cost of this power was estimated to be 28.1 mills/kWh plus 10 percent, or 30.9 mills/kWh, and it was included it as part of the Slice Revenue Requirement.

In the WP-02 rate case, BPA set the ConAug expense as a fixed amount that was not subject to the Slice True-Up. This fixed amount was limited to the first 20 aMW of ConAug acquired each year during the FY 2002-2006 rate period. Slice customers paid their share of the estimated costs of 100 aMW of ConAug during the FY 2002-2006 rate period. If BPA acquired more than 20 aMW during any given year, those costs would be handled through the Load-Based Cost Recovery Adjustment Clause (CRAC) and included in related charges to both Slice and non-Slice customers.

BPA independently decided to capitalize the costs of actual ConAug acquisitions. As a result, there are annual amortization expenses associated with ConAug investments from the FY 2002-2006 rate period that carry over into FY 2007-2009. (*See* Revenue Requirement Study Documentation, Vol. 1, WP-07-FS-BPA-02A, Table 3F, at 51, line 6.) These investments are amortized over the term of the Subscription contracts and are not fully amortized until 2011. However, Slice customers will not pay for these ConAug amortization costs in the FY 2007-2009 rate period because Slice customers paid a forecast of ConAug costs as if they were incurred as annual expenses. Therefore, the amortization will be excluded from the Slice Revenue Requirement and the Actual Slice Revenue Requirement.

9.4.4.3 IOU Residential Exchange Program (REP) Settlement Benefits

In the WP-07 Final Proposal, Slice customers were obligated to pay their proportionate share of any IOU REP Settlement benefits payments to PNW IOUs under the IOU REP Settlement Agreements during the FY 2007-2009 rate period. As a result of a series of decisions by the Ninth Circuit, the IOU REP benefit payments to PNW IOUs will be recalculated for FY 2007-2009. Slice customers paid their proportionate share of forecast IOU REP Settlement benefits through their Slice rate in FY 2007-2008. Slice customers will receive their share of the difference between the forecast IOU REP Settlement benefits for FY 2007-2008 and the recalculated IOU REP benefit payments for FY 2007-2008 through BPA payments to Slice customers, per the WP-07 Supplemental ROD.

The forecast IOU REP Settlement benefits were included as an expense in the FY 2007-2009 Slice Revenue Requirement that was determined in the WP-07 Final Proposal. This forecast of IOU REP Settlement benefits did not reflect any changes related to the decisions by the Ninth Circuit. The forecast IOU REP Settlement benefits are explained below.

There were two aspects to the payments to the IOUs that were included in the Slice Revenue Requirement determined in the WP-07 Final Proposal: (1) the interest of the balance of the FY 2003 $55 million deferral for all IOUs not repaid as of September 30, 2006, and (2) IOU REP Settlement benefits to all six IOUs (Avista Corporation, Idaho Power Company, NorthWestern Energy Division of NorthWestern Corporation, Portland General Electric Company (PGE), PacifiCorp, and Puget Sound Energy) applied to the FY 2007-2011 period, specified under their contracts or contract amendments titled *Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007-2011*.

The balance of the $55 million payment deferral for all IOUs not repaid as of September 30, 2006, was accounted for as an expense in FY 2003, and the Slice customers paid their proportionate share of this expense through the True-Up Adjustment in that year. Therefore the balance still owed on September 30, 2006, was not included as an expense in the Slice Revenue Requirement for purposes of calculating the Slice rate, nor was it accounted for as an expense in the Actual Slice Revenue Requirement for the FY 2007-2008 period for purposes of the annual Slice True-Up.

The interest associated with the $55 million, forecast to be approximately $1 million annually, was included in the FY 2007-2009 Slice Revenue Requirement determined in the WP-07 Final Proposal for purposes of calculating the Slice rate. The interest also was to be accounted for as an expense in the Actual Slice Revenue Requirement for calculation of the True-Up Adjustment Charge in the FY 2007-2009 period. Because of the decisions by the Ninth Circuit, this expense has been eliminated, and any necessary adjustment for FY 2007 and FY 2008 will be addressed through the Slice True-Up for FY 2008.

The second aspect to the payments to the IOUs was the "IOU REP Settlement benefits to all six IOUs." In May 2004, all six IOUs signed contracts or contract amendments entitled, "Agreement Regarding Payment of Residential Exchange Program Settlement Benefits during FY 2007-2011." These contracts and contract amendments apply to FY 2007-2011 and specify that BPA will provide monetary benefits rather than physical power to each of the six IOUs. The contracts and contract amendments also specify a mark-to-market methodology for determining the amount of the monetary benefits based upon the difference between a market price and the lowest-cost PF rate. (*See* Petty, *et al.*, WP-07-E-BPA-11.)

The amount of the IOU REP Settlement benefits payments to all six IOUs was not fixed but rather would change each year depending on the difference between an independent market price forecast and the lowest-cost PF rate (including any CRAC or DDC). In addition to the new methodology, the FY 2007-2011 contracts or contract amendments provide both a floor and a cap for benefit levels. The IOU REP Settlement benefits to be paid by BPA during any fiscal year had a floor of $100 million and a cap set at $300 million. BPA forecasted the benefit amount to be at or near the cap during all three years of the FY 2007-2009 rate period and included this amount in the Slice Revenue Requirement that was determined in the WP-07 Final Proposal. (*See* Table 9.4.1, Slice Product Costing and True-Up Table, line 28). Because of the decisions by the Ninth Circuit, this expense has been eliminated, and any necessary adjustment for FY 2007 and FY 2008 will be addressed through the Slice True-Up for FY 2008.

9.4.4.4 Cost of the Residential Exchange for Public Utilities

Slice customers are responsible for paying their proportionate share of the net costs of the REP for public utilities. The net cost of the REP for public utilities was calculated by subtracting the gross exchange revenues from the gross exchange expenses. (*See* WPRDS Documentation, WP-07-FS-BPA-05A, Table 3.6.2 at 58.) An amount of net costs of the REP for public utilities was forecast for each year of the FY 2007-2009 rate period, and is included in the Slice Revenue Requirement. The actual costs of the REP for public utilities in any year will be included in the Actual Slice Revenue Requirement for that year, for purposes of calculating the Slice True-Up.

9.4.4.5 Bad Debt Expense

The Slice Revenue Requirement contained a line item labeled “Bad Debt Expense.” “Bad Debt Expense” is a line item in Power Service’s Statement of Revenues and Expenses. While no amounts were forecast for bad debt expense for the FY 2007-2009 period, the Actual Slice Revenue Requirement will contain the actual amount accounted for as bad debt expense, except for bad debt expense associated with the sale of energy to any customer that purchases exclusively under the FPS-07 rate schedule, as established in the *Partial Resolution of Issues.* (*See* Evans, *et al.*, WP-07-E-BPA-31, Attachment A.) However, any bad debt expense associated with the sale of energy under both the PF-07 and FPS-07 or just the PF-07 rate schedule, will be included in the Actual Slice Revenue Requirement for Slice True-Up purposes. Through the annual Slice True-Up, Slice customers paid their proportionate share of the eligible bad debt expenses. *Id.*, at A-4.

The Slice Settlement contains a provision that addresses the treatment of bad debt related to California Independent System Operator (CAISO) and California Power Exchange (Cal PX). In regards to CAISO and Cal PX bad debt, BPA reversed the True-Up Adjustment charges to Slice customers for the bad debt expense arising out of transactions with the CAISO and Cal PX prior to October 1, 2001. As a result, Slice customers will not receive any future credits for subsequent recovery of any receivables related to amounts previously written off that BPA collects, nor will the Slice customers pay for any future bad debt expense related to write-offs of any outstanding CAISO or Cal PX receivables.

In addition, the Slice Settlement contains a provision that addresses the treatment of bad debt related to Direct Service Industries (DSIs). This provision specifically states that allowances for uncollectible DSI liquidated damages for FY 2002 or prior years will not be included in the Actual Slice Revenue Requirement or Slice True-Up Adjustment Charge. As a result, Slice customers will not receive any future credits for subsequent recovery of any receivables related to amounts previously written off that BPA collects from DSIs.

9.4.4.6 DSI Costs of Service

On June 30, 2005, BPA's Administrator signed the Record of Decision *Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011* (DSI ROD). In this decision, the Administrator determined that BPA would offer 560 aMW of service benefits to the aluminum smelters, capped at an annual cost of $59 million, plus 17 aMW of power to Port Townsend Paper Corporation, for the FY 2007-2011 period. (*See* Gustafson, *et al.*, WP-07-E-BPA-17.)

These costs are included in the Slice Revenue Requirement and were subject to the annual Slice True-Up. Slice customers paid their proportionate share of these costs.

9.4.4.7 Fish and Wildlife Program Costs

Slice customers are obligated to pay their proportionate share of BPA's direct program costs for fish and wildlife, both BPA's direct program as well as Corps of Engineers and U.S. Bureau of Reclamation costs. Slice customers also experienced their proportionate share of BPA's indirect, or operational, program costs for fish and wildlife directly, through reduced or changed Slice power deliveries.

If BPA's fish and wildlife obligations differed from the forecasts contained in the Slice Revenue Requirement, Slice customers payidtheir proportionate share of any increase or decrease in fish and wildlife annual expenses through their annual True-Up. Slice customers were affected in real time for any changes in indirect program costs (*e.g.*, changed operations or increases in spill and flow) for fish and wildlife through changes in their Slice power deliveries.

Slice customers are not subject to either the National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) (NFB) Adjustment or the Emergency NFB Surcharge. As already mentioned, Slice customers paid their proportionate share of any changes in fish and wildlife annual expenses through their annual True-Up, and any indirect program cost changes were experienced through changes in Slice power deliveries.

9.4.4.8 Slice Implementation Expenses

Slice Implementation Expenses are defined as those costs reasonably incurred by Power Services in any Contract Year (same as BPA's Fiscal Year) for the sole purpose of implementing the Slice product, and that would not have been incurred had Power Services not sold Slice Output under the Block and Slice Power Sales Agreement. Therefore, if Power Services incurs costs during any Contract Year for the purpose of implementing the Slice product, Power Services will account for these as expenses and will charge 100 percent of these expenses to the Slice customers through the annual Slice True-Up.

The Slice Settlement contains a provision that addresses the treatment of Slice Computer Application Project costs. The Slice Settlement states that, consistent with BPA's Software Capitalization Policy or Personal Property Capitalization Policy, any hardware or software acquired for the Slice Computer Application Project and for implementing the Block/Slice PSA will be capitalized over the shorter of a five-year period or the remainder of the Block/Slice contract term, which ends on September 30, 2011. This represents a change from what was proposed in the WP-07 Final Proposal, where all Slice Computer Application Project costs were treated as current expenses, rather than capitalized and recovered over a five-year period.

Projections of Slice Implementation Expenses were not included in the Slice Revenue Requirement, and therefore were not included in the Slice rate for FY 2007-2008. Slice Implementation Expenses in any given Contract Year were accounted for after the audited year-end Actual Slice Revenue Requirement for that Contract Year was available. Slice Implementation Expenses were charged to Slice customers through the annual Slice True-Up for that Contract Year.

9.4.4.9 Debt Optimization Program

Through the Debt Optimization program, BPA refinances (extends the maturities of) Energy Northwest (EN) bonds as they come due and repays an equivalent amount of Federal debt. In total, the same amount of debt is repaid that rates were set to recover, but with an emphasis toward repaying Federal debt rather than non-Federal debt. (*See* Homenick, *et al.*, WP-07-E-BPA-10, Chapter 3.)

The financial effects from the refinancing and the related additional amortization of Federal debt are properly and fully accounted for in the Actual Slice Revenue Requirement, in accordance with the manner in which they are accounted for in Power Services' statement of revenues and expenses and in the determination of business line financial reserves.

The Debt Optimization program is a BPA debt management policy that affects not only the Slice rate (through the annual True-Up Adjustment Charge), but is a recognized factor of BPA's rate of general application through the implementation of the CRAC. Inclusion of the Debt Optimization program transactions in the annual True-Up Adjustment Charge is recognition of the Slice customers' share of these obligations.

9.4.4.10 Reinvestment of "Green Tag Revenues" in BPA's Renewable Resources Facilitation and Research and Development

BPA reinvested what it collectively refers to as "Green Tag revenues" in BPA's renewable resource facilitation and in renewables research and development. These "Green Tag revenues" came from three sources: (1) Green Energy Premium revenues resulting from sales of Environmentally Preferred Power (EPP); (2) Green Tag revenues resulting from sales of Renewable Energy Certificates (RECs); and (3) revenues from sales of Alternative Renewable Energy (ARE) to Pre-Subscription power purchasers. BPA did not include the renewables expense associated with the reinvestment of "Green Tag revenues" in the Slice Revenue Requirement nor the Actual Slice Revenue Requirement. (*See* Evans, *et al.*, WP-07-E-BPA-31, Attachment A, at A-4–A-5, Partial Resolution of Issues.)

9.4.4.11 Minimum Required Net Revenues Calculation

Minimum Required Net Revenues was a component of the annual Generation Revenue Requirement. Minimum Required Net Revenues also was a component of the Slice Revenue Requirement. Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the power repayment studies and any other cash requirements such as payment of irrigation assistance. (*See* Revenue Requirement Study, WP-07-FS-BPA-02, at 20, lines 17-21.) BPA determined that the annual amounts for Minimum Required Net Revenue in the Slice Product Costing and True-Up Table should be different than the amounts that appear in the total Generation Revenue Requirement. These differences are appropriate. (*See* Lee, *et al.*, WP-07-E-BPA-35, at 4, lines 21-24.) The differences are due to one element that is different between the two Minimum Required Net Revenues calculations. In the total Generation Revenue Requirement, accrual revenues that are included in the revenue forecast must be taken into account. Since these are non-cash revenues, the Minimum Required Net Revenues calculation must adjust cash from current operations to ensure adequate coverage of the annual cash requirements in order to demonstrate full cost recovery for proposed power rates. (*See* Revenue Requirement Study, WP-07-FS-BPA-02, at 28.) These accrual revenues stem from a settlement in which BPA/Power Services received cash payments that, in the accounting treatment, are recognized as revenues on a straight-line basis over the remainder of the term of the settled contracts. However, these settlements and the associated accrual revenues were not relevant to cost recovery for Slice and do not appear in the calculation of Minimum Required Net Revenues for the Slice Revenue Requirement (which is represented by the Slice Product Costing and True-Up Table). Due to this difference, the Minimum Required Net Revenues in the Slice Product Costing and True-Up Table was smaller than the Minimum Required Net Revenues in the total power revenue requirement.

9.4.5 Slice Rate

The Slice Revenue Requirement was the basis for calculating the base Slice rate. To calculate the Slice rate that was in effect for FY 2007-2008, the total dollar amounts for each fiscal year of the Slice Revenue Requirement were summed and divided by 36 months (the number of months in the three-year rate period FY 2007-2009 for the WP-07 Wholesale Power Rate Final Proposal) and divided by 100 to obtain the base Slice rate per percent of Slice product purchased. (*See* Table 9.4.1, Slice Product Costing and True-Up Table, line 163.) The monthly Slice rate was $1,877,054 per percent Slice product purchased for FY 2007-2008.

9.4.6 Slice True-Up

Because the Slice rate is calculated as a uniform monthly rate for the rate period and does not take into account the variability of actual costs from year to year, BPA will true-up the difference between the expenses and credits in the average Slice Revenue Requirement for the applicable period upon which the Slice rate is based and the actual expenses and credits in the Actual Slice Revenue Requirement for the applicable fiscal year. The Actual Slice Revenue Requirement for the applicable fiscal year is the sum of the final audited expenditures and revenues as reflected on BPA's Power Services financial statements, corresponding to those Power Service expense and revenue categories that are included in the Slice Revenue Requirement. BPA's financial statements contain expenses and credits that are in accordance with GAAP. Any difference between the Actual Slice Revenue Requirement and the average Slice Revenue Requirement is called the Slice True-Up Amount. The Slice Settlement (*see* section 9.4.3) specifies that BPA's True-Up calculation will be the Actual Slice Revenue Requirement for the applicable fiscal year minus the **average** Slice Revenue Requirement for the applicable rate period.

A positive or negative result from the calculation resulted in an additional charge or credit to the Slice customer. This additional charge or credit to the Slice customer was known as the Slice

True-Up Adjustment Charge (or Credit). Because of the Slice True-Up Adjustment Charge (or Credit), Slice customers paid a percentage of BPA's actual costs, regardless of weather, streamflow, market, or generation output conditions. This assured payment of actual costs mitigates BPA's financial risks in the event that any of these conditions put adverse financial pressure on BPA. The Slice customers' payments through their base Slice rate and the annual True-Up Adjustment Charge mitigate the risk associated with the variability of BPA's expenses and revenue credits (for those expenses included in the Slice Revenue Requirement). The risks associated with the variability of generation output and with the uncertainty of market prices for purchasing or selling power were assumed directly by the Slice customers.

Table 9.4.1
Slice Product Costing and True-Up Table

	($000s)	Audited Actual Data	FY 2007 forecast	FY 2008 forecast	FY 2009 forecast
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)		263,669	188,688	242,902
5	BUREAU OF RECLAMATION		71,654	74,760	77,766
6	CORPS OF ENGINEERS		161,519	165,742	170,407
7	LONG-TERM CONTRACT GENERATING PROJECTS		24,932	25,314	25,751
8	**Sub-Total**		**521,774**	**454,504**	**516,826**
9	**Operating Generation Settlement Payment**				
10	COLVILLE GENERATION SETTLEMENT		16,968	17,354	17,749
11	SPOKANE GENERATION SETTLEMENT		0	0	0
12	**Sub-Total**		**16,968**	**17,354**	**17,749**
13	**Non-Operating Generation**				
14	TROJAN DECOMISSIONING		5,400	4,700	3,100
15	WNP-1&3 DECOMISSIONING		200	200	200
16	**Sub-Total**		**5,600**	**4,900**	**3,300**
17	**Contracted Power Purchases**				
18	PNCA HEADWATER BENEFIT		1,714	1,714	1,714
19	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)				
20	DSI MONETIZED POWER SALE		59,000	59,000	59,000
21	OTHER POWER PURCHASES (short term - omit)				
22	**Sub-Total**		**60,714**	**60,714**	**60,714**
23	**Augmentation Power Purchases**				
24	AUGMENTATION POWER PURCHASES (omit - calculated below)				
25	CONSERVATION AUGMENTATION (omit)				
26	**Residential Exchange/IOU Settlement Benefits**				
27	PUBLIC RESIDENTIAL EXCHANGE (net costs)		**6,762**	**6,811**	**6,861**
28	IOU RESIDENTIAL EXCHANGE		**301,000**	**301,000**	**301,000**
29	**Renewable Generation (expenses related to reinvestment removed)**		**30,289**	**34,719**	**40,835**
30	**Generation Conservation**				
31	LOW INCOME WEATHERIZATION & TRIBAL		5,000	5,000	5,000
32	ENERGY EFFICIENCY DEVELOPMENT		12,885	12,908	12,933
33	ENERGY WEB		1,000	1,000	1,000
34	**LEGACY (Until 11/1/03 this was included with line 72)**		3,728	2,638	2,114
35	MARKET TRANSFORMATION		10,000	10,000	10,000
36	TECHNOLOGY LEADERSHIP		1,300	1,300	1,300
37	INFRASTRUCTURE SUPPORT AND EVALUATION		1,000	1,000	1,000
38	BI-LATERAL CONTRACT ACTIVITY		1,000	1,000	1,000
39	**Sub-Total**		**35,913**	**34,846**	**34,347**
40	CONSERVATION RATE CREDIT		36,000	36,000	36,000
41	**Power System Generation Sub-Total**		**1,015,019**	**950,848**	**1,017,632**
42					
43	**PBL Transmission Acquisition and Ancillary Services**				
44	**PBL Transmission Acquisition and Ancillary Services**				
45	PBL - TRANSMISSION & ANCILLARY SERVICES				
45a	Canadian Entitlement Agreement Transmission Expenses		24,806	25,550	26,991
45b	PNCA & NTS Transmission and System Obligaton Expenses		1,775	1,825	1,875
46	3RD PARTY GTA WHEELING		47,000	47,000	48,000
47	PBL - 3RD PARTY TRANS & ANCILLARY SVCS				
48	RESERVE & OTHER SERVICES		8,462	8,462	8,462
49	TELEMETERING/EQUIP REPLACEMT		200	200	200
50	**PBL Trans Acquisition and Ancillary Services Sub-Total**		**82,243**	**83,037**	**85,528**
51					
52	**Power Non-Generation Operations**				
53	**PBL System Operations**				
54	EFFICIENCIES PROGRAM (omit TMS expenses)		0	0	0
55	INFORMATION TECHNOLOGY		0	0	0
56	GENERATION PROJECT COORDINATION		5,637	5,738	5,844
57	SLICE IMPLEMENTATION (omit - calculated separately)				
58	**Sub-Total**		**5,637**	**5,738**	**5,844**
59	**PBL Scheduling**				
60	OPERATIONS SCHEDULING		8,758	9,051	9,353
61	OPERATIONS PLANNING		5,202	5,358	5,521
62	**Sub-Total**		**13,960**	**14,409**	**14,874**
63	**PBL Marketing and Business Support**				
64	SALES & SUPPORT		15,884	16,278	16,745
64a	Contractual exclusion		(5,360)	(5,360)	(5,360)
65	PUBLIC COMMUNICATION & TRIBAL LIAISON				
66	STRATEGY, FINANCE & RISK MGMT		10,965	11,359	11,771
67	EXECUTIVE AND ADMINISTRATIVE SERVICES		845	840	834
68	CONSERVATION SUPPORT (EE staff costs)		6,441	6,692	6,953
69	**Sub-Total**		**28,776**	**29,808**	**30,943**
70	**Power Non-Generation Operations Sub-Total**		**48,372**	**49,955**	**51,662**
71					
72	**Fish and Wildlife/USF&W/Planning Council**				
73	**BPA Fish and Wildlife (includes F&W Shared Services)**				
74	FISH & WILDLIFE		143,000	143,000	143,000
75	F&W HIGH PRIORITY ACTION PROJECTS				
76	**Sub-Total**		**143,000**	**143,000**	**143,000**
77	**PBL-USF&W Lower Snake Hatcheries**				
78	USF&W LOWER SNAKE HATCHERIES		18,600	19,500	20,400
79	**PBL - Planning Council**				
80	PLANNING COUNCIL		9,085	9,276	9,467
81	**PBL - ENVIRONMENTAL REQUIREMENTS**				
82	ENVIRONMENTAL REQUIREMENTS		500	500	500
83	**Fish and Wildlife/USF&W/Planning Council Sub-Total**		**171,185**	**172,276**	**173,367**
84					

Table 9.4.1
Slice Product Costing and True-Up Table

84					
85	**BPA Internal Support**				
86	**CSRS/FERS**				
87	ADDITIONAL POST-RETIREMENT CONTRIBUTION	10,550	9,000	15,375	
88	**Corporate Support - G&A (excludes direct project support)**				
89	CORPORATE G&A	50,247	51,753	51,764	
90	**TBL Supply Chain - Shared Services**	368	374	380	
91	**General and Administrative/Shared Services Sub-Total**	**61,165**	**61,127**	**67,519**	
92					
93	**Bad Debt Expense**				
94	**Other Income, Expenses, Adjustments**	**1,800**	**1,800**	**3,600**	
95	**Non-Federal Debt Service**				
96	**Energy Northwest Debt Service**				
97	COLUMBIA GENERATING STATION DEBT SVC	195,690	217,856	218,767	
98	WNP-1 DEBT SVC	147,941	165,916	163,282	
99	WNP-3 DEBT SVC	151,724	160,092	153,030	
100	EN RETIRED DEBT				
101	EN LIBOR INTEREST RATE SWAP				
102	**Sub-Total**	**495,355**	**543,864**	**535,079**	
103	**Non-Energy Northwest Debt Service**				
104	TROJAN DEBT SVC	8,605	7,888	0	
105	CONSERVATION DEBT SVC	5,203	5,198	5,188	
106	COWLITZ FALLS DEBT SVC	11,619	11,583	11,571	
107	WASCO DEBT SVC	0	1,664	2,168	
108	**Sub-Total**	**25,427**	**26,333**	**18,927**	
109	**Non-Federal Debt Service Sub-Total**	**520,782**	**570,197**	**554,006**	
110					
111					
112	**Total Operating Expenses**	**1,900,566**	**1,889,240**	**1,953,313**	
113					
114	**Other Expenses**				
115	Depreciation (excl. TMS)	118,058	121,829	124,594	
116	Amortization (excludes ConAug amortization)	55,567	60,241	65,172	
117	Net Interest Expense	163,080	173,193	182,940	
118	LDD	22,289	22,612	22,853	
119	Irrigation Rate Mitigation Costs	10,000	10,000	10,000	
120	**Sub-Total**	368,994	387,875	405,559	
121	**Total Expenses**	**2,269,560**	**2,277,115**	**2,358,872**	
122					
123	**Revenue Credits**				
124	Ancillary and Reserve Service Revs. Total	73,131	61,970	62,715	
125	Downstream Benefits and Pumping Power	8,921	8,921	8,921	
126	4(h)(10)(c)	84,707	84,927	84,676	
127	Colville and Spokane Settlements	4,600	4,600	4,600	
128	FCCF				
129	Energy Efficiency Revenues	12,885	12,908	12,933	
130	Miscellaneous	3,420	3,420	3,420	
131	**Total Revenue Credits**	**187,664**	**176,746**	**177,265**	
132					
133	**Augmentation Costs**				
134	**IOU Reduction of Risk Discount (includes interest)**	23,024	23,024	23,024	
135	**Costs in this box are not subject to True-Up**				
136	**Forecasted Gross Augmentation Costs**				
137	Residual augmentation cost	49,005			
138	Other augmentation cost	97,062	95,001	146,903	
139	Minus revenues	67,993	42,972	64,641	
140	**Net Cost of Augmentation**	**101,098**	**75,053**	**105,286**	
141					
142					
143	**Minimum Required Net Revenue calculation**				
144	Principal Payment of Fed Debt for Power	202,331	172,483	185,065	
145	Irrigation assistance	-	2,950	6,590	
146	Depreciation	118,058	121,829	124,594	
147	Amortization	71,658	76,332	81,263	
148	Capitalization Adjustment	(45,937)	(45,937)	(45,937)	
149	Bond Premium Amortization	613	613	185	
150	Principal Payment of Fed Debt exceeds non cash expenses	57,939	22,596	31,550	
151	Minimum Required Net Revenues	57,939	22,596	31,550	
152					
153	SLICE TRUE-UP ADJUSTMENT CALCULATION				**3-Year Total Slice Rev. Reqt.**
154	Annual Slice Revenue Requirement (Amounts for each FY)	**2,240,934**	**2,198,018**	**2,318,443**	$ 6,757,395
155	TRUE UP AMOUNT (Diff. between actuals and forecast)				
156	AMOUNT BILLED (22.6278 percent)				
157	Slice Implementation Expenses (not incl. in base rate)	**2,400**	**2,400**	**2,400**	
158	TRUE UP ADJUSTMENT				
159	Annual Slice Revenue Requirement (Average)	**2,252,465**			
160					
161	**SLICE RATE CALCULATION ($)**				
162	**Monthly Slice Revenue Requirement (3-Year total divided by 36 months)**				**$ 187,705,407**
163	**One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Revenue Requirement divided by 100)**				**$ 1,877,054**
164					
165	**ANNUAL BASE SLICE REVENUES**				**$ 509,683,249**
166	**Annual Slice Implementation Expenses**				**$ 2,400,000**
167	**TOTAL ANNUAL SLICE REVENUES**				**$ 512,083,249**

10. SECTION 7(b)(2) RATE TEST STUDY, FY 2007-2008

10.1 Introduction

This chapter addresses the section 7(b)(2) rate test for FY 2007-2008 Lookback analysis. Recalculations of the section 7(b)(2) rate tests are necessary to determine a base PF Exchange rates to be used in the Lookback Analysis. There are two phases of the 7(b)(2) rate test for the Lookback analysis, the FY 2002-2006 rate test and FY 2007-2009 rate test. The first rate test is discussed in Chapter 6. The second rate test was conducted using the data available from the WP-07 Final Proposal, with assumption changes made to reflect changed conditions due to removal of the REP settlements. Because FY 2007-2008 are within the FY 2007-2009 rate period covered by the WP-07 Final Proposal, all 7(b)(2) rate calculations in this Lookback analysis were conducted using all three years of the rate period and the ensuing four years, FY 2007-2013.

Much of the discussion of the section 7(b)(2) rate test that is presented in Chapter 6 is applicable to this chapter as well. Therefore, this Chapter 10 is limited to a discussion of the differences between Chapter 6 and this chapter of the Lookback Study.

The Lookback Documentation, WP-07-FS-BPA-08A, section 10, contains the documentation of the Excel models and data used to perform the 7(b)(2) rate test. The output of these spreadsheet models is also in the Lookback Documentation, WP-07-FS-BPA-08A, section10.

10.1.1 Purpose and Organization of Study

This section of the Lookback Study is organized in the same manner as Chapter 6, but as applied to FY 2007-2008. Because this Study only discusses differences from Chapter 6, there are no further direct references to tables in Section 10 of the Lookback Documentation (WP-07-FS-BPA-08A). However, section 10 of the Lookback Documentation contains all of the appropriate tables that would otherwise be referenced in this Study.

10.1.2 Basis of Study

10.1.2.1 Implementation Methodology

10.1.2.1.1 Implementation Methodology: Reserve Benefits

The financial consultant was Public Financial Management.

10.1.2.1.2 Implementation Methodology: Rate Modeling

The three spreadsheet models have now been combined into one, RAM2007. RAM2007 calculates annual Program Case rates for this FY 2007-2008 Lookback analysis for the years FY 2007-2009 and the following four years FY 2010-2013. Except for the treatment of Mid-Columbia resources and obsolete conservation resources, which have been removed from the resource stack, the ratemaking methodology of calculating rates for the Program Case of the rate test are identical to those used in calculating the rates in the WP-07 Final Proposal. Data changes between the WP-07 Final Proposal and the FY 2007-2008 Lookback have been limited to different IOU ASCs and exchange load forecasts.

10.2 Methodology

10.2.1.1.1 Rate Design

The net industrial margin is 0.573 mills/kWh in nominal dollars.

10.2.1.1.2 Sales

For the FY 2007-2013 rate test period, no power sales to DSIs are forecast for the Program Case, and thus no DSI loads are added in the 7(b)(2) Case. However, about $55 million per year in DSI benefit-related program costs are included in both the Program Case and the 7b2 Case revenue requirement.

10.2.1.1.3 Financing Benefits

The financial advisor's analysis is included in the Final Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix A . It shows that the estimated financing benefit of BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by public utilities is 18 basis points lower than the 7(b)(2) Case without BPA backing using 25-year term financing (5.24 percent versus 5.42 percent). The financing benefit of BPA backing for conservation resources in the Program Case would be 17 and 16 basis points lower than the financing costs in the 7(b)(2) Case if financing terms of 20 and 15 years were used. 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. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 5 basis points between an assumed revenue bond issued with and without a BPA contract for the Project.

10.3 Summary of Results

Results for the two cases are summarized in Tables 10.1 and 10.2 below.

10.3.1 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 in Chapter 9. Table 10.1 below shows the projection of undiscounted nominal Program Case rates.

10.3.2 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) 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 10.2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

10.3.3 The Rate Test

RAM2007 performs the section 7(b)(2) 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 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 7(g) costs quantified for the WP-07 Final Proposal rate test are comprised of BPA’s acquired and projected conservation and billing credits, energy efficiency costs, and CRC costs. The projected rates for each year then are discounted to the beginning of FY 2007 using factors based on BPA's projected borrowing rate for each year. Table 10.3 shows BPA's future borrowing rates that were used in the discounting procedure and the corresponding cumulative discount factors. The discounted rates for each case then are averaged over the test period, rounded to one decimal place, and compared (see Table 10.4). As shown in Table 10.4, the rate test triggers by 3.4 mills/kWh. Therefore, a rate adjustment, valued at about $208 million per year, is required.

TABLE 10.1
PROGRAM CASE RATES
(Nominal mills/kWh)

Applicable Fiscal Year	Rate	7(g) Costs	Net Rate
2007	29.65	1.79	27.86
2008	29.68	1.78	27.90
2009	31.62	1.86	29.75
2010	31.27	1.94	29.34
2011	33.00	1.89	31.11
2012	33.39	1.89	31.49
2013	35.05	1.96	33.09

TABLE 10.2
7(b)(2) CASE RATES
(Nominal mills/kWh)

Fiscal Year	7(b)(2) Rate
2007	27.83
2008	23.25
2009	24.49
2010	24.38
2011	26.30
2012	25.74
2013	25.77

TABLE 10.3
DISCOUNT FACTORS FOR THE RATE TEST
Annual BPA Cumulative

Fiscal Year	Borrowing Rate	Discount Factor
2007	.0667	.9375
2008	.0698	.8763
2009	.0722	.8173
2010	.0752	.7601
2011	.0759	.7065
2012	.0757	.6568
2013	.0755	.6107

TABLE 10.4
COMPARISON OF RATES FOR TEST
(Discounted mills/kWh)

Fiscal Year	Discounted Program Case Rate	Discounted 7(b)(2) Case Rate
2007	26.12	26.09
2008	24.44	20.37
2009	24.31	20.02
2010	22.30	18.53
2011	21.98	18.58
2012	20.69	16.90
2013	20.21	15.74
Average Rate	22.9	19.5

Difference of Average Rates 3.4

APPENDIX A

Section 7(b)(2) Rate Test Study
Rates Analysis Model - Resource Stack

FY2007-2008 Lookback Study

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack - FY 2007-2008 Lookback Analysis

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WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack - Rates Analysis Model - Resource Sort Spread Sheet
FY 2007-2008 Lookback Study

7b2 New Resource Sort **7b2 Resource_03**

All Costs are in 1980 dollars, no lost revenues are 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 ($ooo)	Year Available	Capacity Factor	Life	Annual Capital Cost ($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 least cost first.																
PRIEST RAPIDS 1959 ND	1959	20.2		0	1,251	0	2007	100	70	0	0	22,506	15,916	1.82	1251	N
BPA PROG CONS	2001	18.5	5.34	29	10,238	0	2007	100	20	2	29	10,238	27,750	3.17	2	Y
BPA PROG CONS	2000	14.7	5.34	183	8,092	0	2007	100	20	15	181	8,092	28,141	3.21	15	Y
WANAPAM 1963 ND		0.0		0	0	0	2007	100	35	0	0	1	28,300	3.23	0	N
BPA PROG CONS	1997	54.7	5.34	18,136	13,912	0	2007	100	20	1,497	18,015	13,912	29,184	3.33	1497	Y
BPA PROG CONS	1999	30.3	5.34	10,576	11,074	0	2007	100	20	873	10,505	11,074	35,609	4.06	873	Y
BPA PROG CONS	2004	31.0	5.09	9,368	7,627	0	2007	100	15	908	9,163	7,627	36,108	4.12	908	Y
IDAHO FALLS	1982	18.5		0	2,615	0	2007	100	60		0	46,214	41,635	4.75	2615	N
BOARDMAN PUBLIC ND	1980	40.7			4,278	0	2007	100	60	1,609	28,430	75,603	42,654	4.87	5887	N
BPA PROG CONS	1998	33.4	5.34	14,299	16,394	0	2007	100	20	1,181	14,204	16,394	45,806	5.23	1181	Y
BPA PROG CONS	1996	56.3	5.34	29,274	27,405	0	2007	100	20	2,417	29,079	27,405	50,164	5.73	2417	Y
BPA PROG CONS	2003	24.7	5.09	11,323	8,547	0	2007	100	15	1,097	11,075	8,547	52,960	6.05	1097	Y
BPA PROG CONS	1995	65.9	5.34	48,677	26,640	0	2007	100	20	4,019	48,354	26,640	56,900	6.50	4019	Y
BPA PROG CONS	2002	25.7	5.09	14,231	8,643	0	2007	100	15	1,379	13,920	8,643	58,529	6.68	1379	Y
NINE CANYON WIND PROJ. ND	2006	8.1		0	1,249	0	2007	100	35	0	0	19,411	68,134	7.78	1249	N
COWLITZ FALLS	1994	26.0	4.25	0	1,088	0	2007	100	60	5,130	90,655	19,233	70,441	8.04	6218	N
BPA PROG CONS	1994	51.3	5.34	70,666	30,512	0	2007	100	20	5,835	70,196	30,512	98,157	11.21	5835	Y
BPA PROG CONS	2013	33.0	5.09	15,617	33,410	0	2007	100	15	1,514	15,276	33,410	98,354	11.23	1514	Y
BPA PROG CONS	2009	33.0	5.09	13,517	35,479	0	2007	100	15	1,310	13,221	35,479	98,384	11.23	1310	Y
BPA PROG CONS	2005	21.6	5.09	10,523	21,781	0	2007	100	15	1,020	10,293	21,781	98,994	11.30	1020	Y
BPA PROG CONS	2012	33.0	5.09	15,934	33,616	0	2007	100	15	1,544	15,586	33,616	99,396	11.35	1544	Y
BILLING CREDITS	1996	11.9		0	2,441	0	2007	100	30	0	0	35,798	100,276	11.45	2441	N
BPA PROG CONS	2011	33.0	5.09	16,260	33,838	0	2007	100	15	1,576	15,905	33,838	100,491	11.47	1576	Y
BPA PROG CONS	2008	33.0	5.09	13,788	36,278	0	2007	100	15	1,336	13,487	36,278	100,534	11.48	1336	Y
BPA PROG CONS	2010	33.0	5.09	16,576	34,422	0	2007	100	15	1,607	16,213	34,422	102,294	11.68	1607	Y
WAUNA-Steam-Cogen.	1996	23.0		0	4,832	0	2007	100	30	0	0	70,852	102,684	11.72	4832	N
BPA PROG CONS	2007	33.0	5.09	14,100	37,357	0	2007	100	15	1,367	13,791	37,357	103,330	11.80	1367	Y
BPA PROG CONS	2006	26.6	5.09	19,943	21,875	0	2007	100	15	1,933	19,506	21,875	103,713	11.84	1933	Y

BPA's Wholesale Power 2007 Supplemental Rate Case
FY 2007-2008 Lookback Analysis
BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings

NOMINAL DOLLARS IN THE YEAR OF INVESTMENT

Appendix D, page D-22, WP-07-FS-BPA-06

($ 000)

	Conser. Savings aMW		Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Amortization Period Years
1982	32.4		4,974	61,940	66,914	20
1983	68.6		2,907	204,092	206,999	20
1984	16.6		8,311	66,783	75,094	20
1985	17.0		24,680	103,067	127,747	20
1986	23.5		5,256	99,743	104,999	20
1987	17.2		3,928	71,631	75,559	20
1988	15.6		6,654	58,570	65,224	20
1989	20.8		12,917	46,069	58,986	20
1990	13.2		35,796	36,220	72,016	20
1991	19.0		37,557	45,714	83,271	20
1992	37.4		63,943	62,151	126,094	20
1993	59.6		55,253	96,717	151,970	20
1994	51.3		52,350	121,242	173,592	20
1995	65.9		46,657	85,252	131,909	20
1996	56.3		48,937	52,274	101,211	20
1997	54.7		25,279	32,953	58,232	20
1998	33.4		30,188	26,331	56,519	20
1999	30.3		20,657	19,728	40,385	20
2000	14.7		15,377	347	15,724	20
2001	18.5		19,905	57	19,962	20
2002	25.7		17,143	28,227	45,370	15
2003	24.7		17,286	22,900	40,186	15
2004	31.0		15,821	19,431	35,252	15
Subtotals	747.4		571,776	1,361,439	1,933,215	
2005	21.6		46,572	22,500	69,072	15
2006	26.6		48,264	44,000	92,264	15
2007	33.0		84,784	32,000	116,784	15
2008	33.0		84,195	32,000	116,195	15
2009	33.0		83,996	32,000	115,996	15
2010	33.0		83,067	40,000	123,067	15
2011	33.0		83,242	40,000	123,242	15
2012	33.0		84,387	40,000	124,387	15
2013	33.0		85,570	40,000	125,570	15
Subtotals	279.2		684,077	322,500	1,006,577	
Cumulative Savings						
1982-2013	**1,026.6**	aMW	**1,255,853**	**1,683,939**	**2,939,792**	
Cumulative Savings						
1982-2006	**795.6**	aMW	**666,612**	**1,427,939**	**2,094,551**	

BPA's Wholesale Power 2007 Supplemental Rate Case
FY 2007-2008 Lookback Analysis
BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings

INVESTMENTS IN 1980 DOLLARS

Inflation / GDP Deflator Indices Based on Global Insight Data - 04/03/2008

			($ 000)		
Inflation Adjustment Factor To Change To 1980 $$		Conser. Savings aMW	Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures
1.173693	1982	32.4	4,238	52,774	57,011
1.230407	1983	68.6	2,363	165,874	168,236
1.277612	1984	16.6	6,505	52,272	58,777
1.320287	1985	17.0	18,693	78,064	96,757
1.354100	1986	23.5	3,882	73,660	77,542
1.388031	1987	17.2	2,830	51,606	54,436
1.431393	1988	15.6	4,649	40,918	45,567
1.483356	1989	20.8	8,708	31,057	39,765
1.540266	1990	13.2	23,240	23,515	46,756
1.596429	1991	19.0	23,526	28,635	52,161
1.641039	1992	37.4	38,965	37,873	76,838
1.678822	1993	59.6	32,912	57,610	90,522
1.715695	1994	51.3	30,512	70,666	101,179
1.751367	1995	65.9	26,640	48,677	75,318
1.785673	1996	56.3	27,405	29,274	56,679
1.817042	1997	54.7	13,912	18,136	32,048
1.841407	1998	33.4	16,394	14,299	30,693
1.865409	1999	30.3	11,074	10,576	21,649
1.900276	2000	14.7	8,092	183	8,275
1.944139	2001	18.5	10,238	29	10,268
1.983459	2002	25.7	8,643	14,231	22,874
2.022504	2003	24.7	8,547	11,323	19,869
2.074232	2004	31.0	7,627	9,368	16,995
	Subtotals	747.4	339,595	920,620	1,260,215
2.138176	2005	21.6	21,781	10,523	32,304
2.206339	2006	26.6	21,875	19,943	41,818
2.269566	2007	33.0	37,357	14,100	51,457
2.320833	2008	33.0	36,278	13,788	50,066
2.367475	2009	33.0	35,479	13,517	48,996
2.413169	2010	33.0	34,422	16,576	50,998
2.459983	2011	33.0	33,838	16,260	50,099
2.510354	2012	33.0	33,616	15,934	49,550
2.561243	2013	33.0	33,410	15,617	49,027
	Subtotals	279.2	288,056	136,257	424,314
		1,026.6	**627,651**	**1,056,878**	**1,684,529**

WP-07 Supplemental Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2007-2013
FY2007-2008 Lookback Analysis - Resource Stack

Billing Credit Resources - Detail

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

	BPA Billing Credits - 7(b)(2) Case Costs - 2007$$				BPA Billing Credits - 7(b)(2) Case Costs - 1980$$			
Summary:	Average MWh	Total MW/Year	Cost Per MWh	Annual Cost	Average MWh	Total MW/Year	Cost Per MWh	Annual Cost
Project A	6.5468	57,350	$59.0752	$3,387,965	6.5468	57,350	$26.03	$1,492,781
Project B	3.5939	31,483	$58.6954	$1,847,908	3.5939	31,483	$25.86	$814,212
Project C	1.7359	15,207	$20.0540	$304,959	1.7359	15,207	$8.84	$134,369
	11.8767	104,040	$53.26	$5,540,832	11.8767	104,040	$23.47	$2,441,362
Annual Cost Data	11.8767	104,040	$53.26	$5,540,832	11.8767	104,040	$23.47	$2,441,362

GDP - Deflator to convert 2007$$ to 1980$$ = 2.269566

Note 1 - The Program Case Revenue requirement includes the Smith Creek Hydro Project for the years of FY2007-2011. The Smith Creek Hydro Project contract terminates on September 30, 2011. Because this resource is not available to serve 7(b)(2) Customer loads during all years of the rate test period it was 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.

Billing Credit Amounts for the Program Case

	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Average Hourly Energy - aMW	17.5	17.5	17.5	17.5	17.5	17.5	17.5
Annual Revenue Requirement Costs	$7,066,000	$7,137,000	$7,308,000	$7,383,000	$7,469,000	$5,873,000	$5,685,000

Project A - South Fork Tolt Hydro Project

				Final 2007-2009 Rates				Declared Project Generation								
Month	**Hours**	HLH	LLH	HLH $/MWh	LLH $/MWh	Demand $/kW	Ld Variance $/MWh	HLH MWh	LLH MWh	Demand kW	Alt Cost[2] $/MWh	PF Power Only $	PTP-06 1.591	AC$ $	PF Power plus Tx $	**Billing Credit** $
October	744	416	328	29.70	21.76	1.94	0.47	4085	0	11200	94.8	143,053	23,865	387,258	166,918	220,341
November	721	416	305	31.68	23.10	2.08	0.47	3966	0	11200	94.8	148,939	23,865	375,977	172,804	203,173
December	744	432	312	33.06	24.26	2.18	0.47	4136	0	11200	94.8	161,152	23,865	392,093	185,017	207,076
January	744	432	312	28.07	20.30	1.85	0.47	4158	0	11300	94.8	137,620	23,865	394,178	161,485	232,693
February	672	368	304	28.66	20.50	1.88	0.47	3783	0	11300	94.8	129,665	23,865	358,628	153,530	205,099
March	743	432	311	26.59	19.49	1.75	0.47	4180	0	11300	94.8	130,921	23,865	396,264	154,786	241,478
April	720	416	304	24.95	17.93	1.64	0.47	4060	0	11300	94.8	119,829	23,865	384,888	143,694	241,194
May	744	416	328	20.84	14.41	1.36	0.47	4933	0	12300	94.8	119,532	23,865	467,648	143,397	324,252
June	720	416	304	18.87	10.02	1.25	0.47	5710	0	13600	94.8	124,748	23,865	541,308	148,613	392,695
July	744	432	312	23.24	17.01	1.53	0.47	6993	0	15000	94.8	185,467	23,865	662,936	209,332	453,604
August	744	416	328	27.21	20.18	1.79	0.47	6702	0	14700	94.8	208,674	23,865	635,350	232,539	402,810
September	720	416	304	28.09	22.54	1.85	0.47	4644	0	12100	94.8	152,835	23,865	440,251	176,700	263,551
	8,760	5,008	3,752					57,350	0	146,500		1,762,435	286,380	5,436,780	2,048,815	3,387,965

Average MWh **6.5468**

Annual Cost per MWh **59.0752**

Note 2 - Alternative cost value is the average of FY2009-2013 contract schedule, Exhibit C, Table 3.

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WP-07 Supplemental Rate Case
Updated Cost Projections for Billing Credit Resources - Purchase Power Contracts
Forecasted Cost of Resource During FY2007-2013
FY2007-2008 Lookback Analysis - Resource Stack

Project B - Wynochee Hydro Project

				Final 2007-2009 Rates				Declared Project Generation									
Month	Hours	HLH	LLH	HLH $/MWh	LLH $/MWh	Demand $/kW	Ld Variance $/MWh	HLH MWh	LLH MWh	Assured Energy Capabilities	Demand kW	Alt Cost[3] $/MWh	AC$ $	PTP-06 1.591	PF Power Costs Only $	PF Power Plus Tx $	Billing Credit $
October	744	416	328	29.70	21.76	1.94	0.47	2,043	1,611	3,654	4,910	90.9	332,149	10,214	105,259	115,473	216,676
November	721	416	305	31.68	23.10	2.08	0.47	2,428	1,781	4,209	5,850	90.9	382,598	10,214	130,232	140,447	242,152
December	744	432	312	33.06	24.26	2.18	0.47	3,042	2,197	5,239	7,040	90.9	476,225	10,214	169,215	179,429	296,796
January	744	432	312	28.07	20.30	1.85	0.47	2,775	2,004	4,779	6,420	90.9	434,411	10,214	130,452	140,666	293,745
February	672	368	304	28.66	20.50	1.88	0.47	2,315	1,912	4,227	6,290	90.9	384,234	10,214	117,367	127,582	256,653
March	743	432	311	26.59	19.49	1.75	0.47	1,425	1,026	2,451	3,290	90.9	222,796	10,214	63,646	73,860	148,936
April	720	416	304	24.95	17.93	1.64	0.47	1,117	816	1,933	2,680	90.9	175,710	10,214	46,894	57,108	118,601
May	744	416	328	20.84	14.41	1.36	0.47	0	0	0	0	90.9	-	10,214	-	10,214	(10,214)
June	720	416	304	18.87	10.02	1.25	0.47	0	0	0	0	90.9	-	10,214	-	10,214	(10,214)
July	744	432	312	23.24	17.01	1.53	0.47	1,045	754	1,799	2,420	90.9	163,529	10,214	40,811	51,026	112,504
August	744	416	328	27.21	20.18	1.79	0.47	912	719	1,631	2,190	90.9	148,258	10,214	43,245	53,459	94,799
September	720	416	304	28.09	22.54	1.85	0.47	902	659	1,561	2,170	90.9	141,895	10,214	44,205	54,419	87,476
	8,760	5,008	3,752					18,004	13,479	31,483	43,260		2,861,805	122,571	891,326	1,013,896	1,847,908
							Average MWh	3.5939						**Annual Cost per MWh**			**$58.6954**

Note 3 - Alternative cost value is the average of FY2009-2013 contract schedule, Exhibit C, page 10, Table 3.

Project C - Short Mountain Landfill Project

	Final 2007-2009 Rates																
	HLH Energy	LLH Energy	Demand	Load Variance	NT-06 Network Integration	LDD	Estimated Firm Energy (MWh) 5/	Sustained Peaking Capability (MW)	Adjusted Alternative Cost 4/	AC$	HLH Energy 57% Split	LLH Energy 43% Split	Gen Demand	Load Variance	Trans Base / Load Shaping	PF$ Includes LDD	Billing Credits
October	29.70	21.76	1.94	0.47	1.583	0.045	1,173.427	3.22	51.3	$60,236	$19,865	$10,980	$6,247	$552	$5,097	$41,046	$19,190
November	31.68	23.10	2.08	0.47	1.583	0.045	1,193.917	3.22	51.3	$61,288	$21,559	$11,859	$6,698	$561	$5,097	$43,944	$17,344
December	33.06	24.26	2.18	0.47	1.583	0.045	1,399.405	3.22	51.3	$71,836	$26,371	$14,598	$7,020	$658	$5,097	$51,554	$20,282
January	28.07	20.30	1.85	0.47	1.583	0.045	1,396.713	3.22	51.3	$71,698	$22,347	$12,192	$5,957	$656	$5,097	$44,398	$27,300
February	28.66	20.50	1.88	0.47	1.583	0.045	1,362.039	3.22	51.3	$69,918	$22,251	$12,006	$6,054	$640	$5,097	$44,205	$25,713
March	26.59	19.49	1.75	0.47	1.583	0.045	1,387.746	3.22	51.3	$71,238	$21,033	$11,630	$5,635	$652	$5,097	$42,295	$28,943
April	24.95	17.93	1.64	0.47	1.583	0.045	1,262.443	3.22	51.3	$64,805	$17,954	$9,733	$5,281	$593	$5,097	$37,148	$27,657
May	20.84	14.41	1.36	0.47	1.583	0.045	1,240.418	3.22	51.3	$63,675	$14,735	$7,686	$4,379	$583	$5,097	$31,248	$32,427
June	18.87	10.02	1.25	0.47	1.583	0.045	1,205.916	3.22	51.3	$61,904	$12,971	$5,196	$4,025	$567	$5,097	$26,831	$35,072
July	23.24	17.01	1.53	0.47	1.583	0.045	1,205.512	3.22	51.3	$61,883	$15,969	$8,817	$4,927	$567	$5,097	$34,015	$27,868
August	27.21	20.18	1.79	0.47	1.583	0.045	1,301.630	3.22	51.3	$66,817	$20,188	$11,295	$5,764	$612	$5,097	$41,252	$25,565
September	28.09	22.54	1.85	0.47	1.583	0.045	1,077.722	3.22	51.3	$55,323	$17,256	$10,445	$5,957	$507	$5,097	$37,725	$17,598
TOTALS							15,206.888			780,620	232,498	126,438	67,942	7,147	61,167	475,661	304,959
					Average MWh		1.7359							**Annual Cost per MWh**			**$20.0540**

4/ Adjusted Alternative Cost is taken from total column on page 12 of Exhibit C Revision 1, average for the three years 2007-2009.
5/ These amounts are final metered energy amounts for the 2005 operating year.

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack

Boardman Coal Plant - Revised Cost Projections for FY 2007-2008 Lookback

7(b)(2) Case - Resource Stack Values:		
	FY2007-$$	**FY1980-$$***
Total Annual O&M (Production Expenses)	9,708,982	4,277,902
Debt Service - FIXED - FY2007 - FY 2013	3,651,008	1,608,681
Total Operating and Financing Costs - (Production and Debt Service)	13,359,989	5,886,583
Cost per MWh	**$37.52**	**$16.53**
Capital Investment - Historical Cost as of FY 2007	628,908,482	NA
Life	60 years	60 years
Placed in service	1980	1980
Net Continuous Plant Capability (MW)	58.50	58.50
Projected Net Annual Generation - MWh - 2005 FERC FORM 1	356,117	356,117
Capacity Factor	69.49%	69.49%
Projected Average Hourly Generation - aMW	40.65	40.65

* Deflator conversion factor of 2.269566, was used to convert the resource cost data that is expressed in 2007 dollars to 1980 dollars.

Global Insight Deflator Value to convert 2007$$ to 1980$$ = 2.269566

Note 1- In order for the FY 2007-2008 Lookback rates model to hold the $1,608,681 of debt service (expressed in 1980 dollars) constant in all years of the rate test period after it was chosen, this amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model. The $4,277,902 in O&M costs (expressed in 1980 dollars) were entered into the annual O&M column of the "7(b)(2) Resource Sort" tab in the rates model.

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack

Summary of FY 2007 Projected Operating and Financing Costs:

	BPA's Projected Boardman - 100% Operating Budget FY 2007	BPA's Projected Boardman - 10% Operating Budget FY 2007
Fuel Cost Data:		
Fuel Cost - FERC # 501	$ 1,826,322	$ 182,632
Fuel Oil Costs		0
Fuel Inventory Oil Purchase #151	551,084	55,108
Payroll Taxes #408	995,863	99,586
Other Misc. Electric Revenues #456	(587,644)	(58,764)
Fuel Inventory - Coal fixed O&M #151	1,891,037	189,104
Coal Fuel Costs #151- line 20 (From Fuel analysis)	58,909,340	5,890,934
TOTAL FUEL COSTS	63,586,002	6,358,600
Operating Cost Data:		
Production Expenses - line 19	6,940,270	694,027
Misc. Steam / Power Expenses FERC #506 & #557- line 26	2,219,821	221,982
Rent Expense #507- line 27		0
Allowances - line 28	0	0
Administrative & General Expenses #921-#930	5,830,619	583,062
TOTAL OPERATION COSTS	14,990,710	1,499,071
Maintenance Expense - line 29	18,513,106	1,851,311
Total Production Expenses	97,089,819	9,708,982
Debt Service Costs (From Financing Plant Cost Analysis)		3,651,008
Total Operating and Financing Costs - 10% Boardman for FY 2007 in 2007$$		**$ 13,359,989**
Cost per MWh in 2007$$		**$37.52**
Net Continuous Plant Capability (MW)	585	58.5
Projected Net Annual Generation - KWh - 2005 FERC FORM 1	3,561,167,344	356,116,734
Projected Net Annual Generation - MWh	3,561,167	356,117
Capacity Factor	69.49%	69.49%
Projected Average Hourly Generation - aMW	406.53	40.65

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WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack

Boardman Operating Cost Historical Data / OY 2008 PGE Operating Budget / FY 2007 Projection:

	PGE's FERC Form No. 1 Data - page 402, column (b), Total Plant Costs								BPA's Projected Boardman Operating Budget	Portland General Electric's Boardman 100% Budget
	FY2004	**FY2004** Restated in FY2007 $$	**FY2005**	**FY2005** Restated in FY2007 $$	**FY2006**	**FY2006** Restated in FY2007 $$	**FY2007**	4-Year Ave Costs Stated in **FY2007 $$**	**FY 2007**	**OY 2008 in 2008 $$**
		0.9285115		0.957948		0.9865435		1.00000		1.021026
Fuel Cost Data:										
Fuel Cost - FERC # 501									1,826,322	1,864,722
Fuel Oil Costs										
Fuel Inventory Oil Purchase #151							(* From fuel Cost Analysis)		551,084 *	813,962
Payroll Taxes #408									995,863	1,016,802
Other Misc. Electric Revenues #456									(587,644)	(600,000)
Fuel Inventory - Coal fixed O&M #151									1,891,037	1,930,798
Coal Fuel Costs #151- line 20	44,256,851	47,664,300	47,834,482	49,934,320	35,492,843	35,976,967	61,041,164	48,654,188	58,909,340 *	62,346,284
TOTAL FUEL COSTS	44,256,851	47,664,300	47,834,482	49,934,320	35,492,843	35,976,967	61,041,164	48,654,188	63,586,002	67,372,568
Operating Cost Data:										
Production Expenses - line 19	6,764,874	7,285,719	5,974,221	6,236,477	5,989,289	6,070,983	6,763,843	6,589,256	6,940,270	7,086,196
Misc. Steam / Power Expenses FERC #506 & #557- line 26	1,192,631	1,284,455	2,169,872	2,265,125	2,066,716	2,094,906	2,169,128	1,953,403	2,219,821	2,266,495
Rent Expense #507- line 27	3,618,051	3,896,614	1,138,860	1,188,854	257,963	261,482	0	1,336,737	0	0
Allowances - line 28	(7,770)	(8,368)	(19,387)	(20,238)	0	0	0	(7,152)	0	0
Administrative & General Expenses #921-#930									5,830,619	5,953,214
TOTAL OPERATION COSTS	11,567,786	12,458,420	9,263,566	9,670,218	8,313,968	8,427,371	8,932,971	9,872,245	14,990,710	15,305,905
Maintenance Expense - line 29	23,694,817	25,519,142	19,345,303	20,194,523	18,802,559	19,059,027	19,406,261	21,044,738	18,513,106	18,902,363
Total Production Expenses	79,519,454	85,641,862	76,443,351	79,799,061	62,609,370	63,463,365	89,380,396	79,571,171	97,089,819	101,580,836

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack
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 - March 2008 # DOE/EIA-0383	33.85	34.52	35.23
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		71.15%	69.49%	47.12%	84.97%	84.97%
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	2,585,987
Average Heat Content - Coal	**FERC Form 1, Page 402**	8,517	8,517	8,517	8,517	8,517
Avg. 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		3,540,097,001	3,561,167,344	2,414,544,179	4,354,534,426	4,354,534,426
Coal Cost (Total)		**41,521,306**	**43,740,794**	**30,894,409**	**58,909,340**	**62,346,284**
Quantity Oil	**FERC Form 1, Page 402**	11,960	7,418	8,006	6178	8390.5
Avg. cost - Oil - per unit burned	**FERC Form 1, Page 402**	46.055	$ 57.53	$ 80.27	89.201	97.01
Oil cost Total		**$ 550,818**	**$ 426,780**	**$ 642,618**	**$ 551,084**	**$ 813,962**
Total Fuel Cost		**$ 42,072,124**	**$ 44,167,574**	**$ 31,537,027**	**$ 59,460,424**	**$ 63,160,246**

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WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack
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	84.97%	84.97%	84.97%	84.97%	84.97%
Fuel					
Fuel Burned					
Quantity Coal (tons)	2,585,987	2,585,987	2,585,987	2,585,987	2,585,987
Average Heat Content - Coal	8,517	8,517	8,517	8,517	8,517
Avg. 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	4,354,534,426	4,354,534,426	4,354,534,426	4,354,534,426	4,354,534,426
Coal Cost (Total)	**65,326,093**	**67,442,738**	**67,721,126**	**67,504,779**	**67,858,393**
Quantity Oil	8390.5	8390.5	8390.5	8390.5	8390.5
Avg. 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**

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack
Analysis of Total Capitalized Cost - Debt Service Amounts for Revenue Requirement

		Cumulative Cost
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 - Agrees to FERC Form No. 1 for 2007, page 402	7,037,182	628,908,482
Total Asset Cost -line 17, FERC Form No. 1		628,908,482
2007 Construction Work in Progress - FERC Form No. 1 for 2007, page 216		2,516,237

Note: PGE's FERC Form 1 Indicates that the plant has a life of 60 years.

Initial Investment Amount

		Total AMT	PRC AMT	Payment Amounts
Total Capitalized Cost - 1980		591,000,000	59,100,000	
Debt/Capital Mix		80 /20	100 / 0	
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
Refi. in 1990 - 30 yr. @ 8%	53,373,945	8.00%	8.00%	4,741,071
Refi. in 2000 - 30 yr. @ 8%	46,548,530	6.00%	6.00%	3,381,700
Payment amount - annual				

			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	58,345,505
	3	1982	6,269,284	5,834,550	434,733	57,910,771
	4	1983	6,269,284	5,791,077	478,206	57,432,565
	5	1984	6,269,284	5,743,256	526,027	56,906,538
	6	1985	6,269,284	5,690,654	578,630	56,327,908
	7	1986	6,269,284	5,632,791	636,493	55,691,415
	8	1987	6,269,284	5,569,142	700,142	54,991,273
	9	1988	6,269,284	5,499,127	770,156	54,221,117
	10	1989	6,269,284	5,422,112	847,172	53,373,945
	11	1990	4,741,071	4,269,916	471,155	52,902,790
	12	1991	4,741,071	4,232,223	508,847	52,393,943
	13	1992	4,741,071	4,191,515	549,555	51,844,388
	14	1993	4,741,071	4,147,551	593,520	51,250,868
	15	1994	4,741,071	4,100,069	641,001	50,609,867
	16	1995	4,741,071	4,048,789	692,281	49,917,586
	17	1996	4,741,071	3,993,407	747,664	49,169,922
	18	1997	4,741,071	3,933,594	807,477	48,362,446
	19	1998	4,741,071	3,868,996	872,075	47,490,371
	20	1999	4,741,071	3,799,230	941,841	46,548,530
	21	2000	3,381,700	2,792,912	588,788	45,959,742
	22	2001	3,381,700	2,757,584	624,116	45,335,626
	23	2002	3,381,700	2,720,138	661,562	44,674,064
	24	2003	3,381,700	2,680,444	701,256	43,972,807
	25	2004	3,381,700	2,638,368	743,332	43,229,476
	26	2005	3,381,700	2,593,769	787,931	42,441,544
	27	2006	3,381,700	2,546,493	835,207	41,606,337
	28	2007	3,381,700	2,496,380	885,320	40,721,017
	29	2008	3,381,700	2,443,261	938,439	39,782,578
	30	2009	3,381,700	2,386,955	994,745	38,787,833
	31	2010	3,381,700	2,327,270	1,054,430	37,733,403
	32	2011	3,381,700	2,264,004	1,117,696	36,615,707
	33	2012	3,381,700	2,196,942	1,184,758	35,430,949
	34	2013	3,381,700	2,125,857	1,255,843	34,175,106

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack
Analysis of Total Capitalized Cost - Debt Service Amounts for Revenue Requirement

Debt Service Requirements - Physical Plant:

SEVEN YEAR (FY 2007-2013) AVERAGE =	3,651,008				
DEBT SERVICE		FY 2007	FY 2008	FY 2009	FY 2010
Initial Investment Amount		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
FY 2007 Additions		55,437	55,437	55,437	55,437
TOTAL ANNUAL DEBT SERVICE		3,651,008	3,651,008	3,651,008	3,651,008

Second Debt financing amount for FY 2005 and prior Additions

	Total AMT	PRC AMT
Total Capitalized Cost - 1981-2006	31,231,117	3,123,112
Debt/Capital Mix	80 /20	100 / 0
Cap.Costs financed in 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 @ 4.75% 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
	29	2033	213,871	21,426	192,445	202,874
	30	2034	213,871	10,996	202,875	(1)

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections -10% Interest in Boardman Coal Plant
FY 2007-2008 Lookback Analysis - Resource Stack
Analysis of Total Capitalized Cost - Debt Service Amounts for Revenue Requirement

	FY 2011	FY 2012	FY 2013	FY 2014	FY 2015
Initial Investment Amount	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
FY 2007 Additions	55,437	55,437	55,437	55,437	55,437
TOTAL ANNUAL DEBT SERVICE	3,651,008	3,651,008	3,651,008	3,651,008	3,651,008

FY 2007 Financing Amount

	Total AMT	PRC AMT
Total Capitalized Cost - 2007	7,037,182	703,718
Debt/Capital Mix	80 /20	100 / 0
Cap.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 @ 4.75% 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	55,437	2,478	52,958	0

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections - Cowlitz Falls Hydro Project for FY 2007- 2013
FY 2007-2008 Lookback Resource Stack

Cowlitz Falls Hydro Project Resource - Revised Cost Projections for FY2007-2008 Lookback Analysis

7(b)(2) Case - Resource Stack Values:	FY2007-$$	FY1980-$$
Total O&M - FY 2007 Year Amount	2,470,000	1,088,314
Debt Service - FIXED - FY2009 - FY 2013	11,642,023	5,129,625
Total Combined Costs - O&M and Debt Service	14,112,023	6,217,939
Cost per MWh	$61.96	$27.30
Capital Investment	195,341,712	NA
Life	30 years	30 years
Placed in service	1994	1994
Average Annual Energy Output/@ 26.0MWh[2]	227,760	227,760

* Inflator conversion factor of 2.269566 was used to convert the resource cost data that is expressed in 2007 dollars to 1980 dollars. 2.269566

Note 1- In order for the FY 2007-2008 Lookback rates model to hold the $5,129,625 of debt service (expressed in 1980 dollars) constant in all years of the rate test period after it was chosen, this amount was entered into the annual capital cost column of the "7(b)(2) Resource Sort" tab in the rates model. The $1,088,314 in (expressed in 1980 dollars) was entered into the annual O&M column of the "7(b)(2) Resource Sort" tab in the rates model.

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack
Updated Cost Projections - Cowlitz Falls Hydro Project for FY 2007- 2013
FY 2007-2008 Lookback Resource Stack

Amounts paid/projected by BPA for the resource - revenue requirement amounts:

GDP Inflation Factors Projections	1.000000	1.021026	1.042052	1.061396	1.082422	1.105130	1.126997
Program Case Revenue Requirement:	**FY2007**	**FY2008**	**FY2009**	**FY2010**	**FY2011**	**FY2012**	**FY2013**
Operation and Maintenance Charges	1,621,618	1,628,780	1,697,273	1,801,479	1,949,961	2,154,960	2,428,633
Transmission Charges	848,382	866,220	897,000	897,000	897,000	940,000	940,000
Debt Service Payments 4.20% Actual	11,619,490	11,582,810	11,571,060	11,566,310	11,562,680	11,559,430	11,546,060
Total Amounts Paid - Program Case Rates	14,089,490	14,077,810	14,165,333	14,264,789	14,409,641	14,654,390	14,914,693
7(b)(2) Case Revenue Requirement:							
Operation and Maintenance Charges	1,621,618	1,628,780	1,697,273	1,801,479	1,949,961	2,154,960	2,428,633
Transmission Charges	848,382	866,220	897,000	897,000	897,000	940,000	940,000
Total O&M	2,470,000	2,495,000	2,594,273	2,698,479	2,846,961	3,094,960	3,368,633
Debt Service Payments @ 4.25%	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023
Total Amounts Paid - 7(b)(2) Case Rates	14,112,023	14,137,023	14,236,296	14,340,502	14,488,984	14,736,983	15,010,656
Average Annual Energy Output/@ 26.0MWh[2]	227,760	227,760	227,760	227,760	227,760	227,760	227,760
Cost per MWh	$61.96	$62.07	$62.51	$62.96	$63.62	$64.70	$65.91

Calculation of 7(b)(2) Debt Service - Average annual Program Case debt service FY2007-2013 = 11,572,549 **= Prog. Case Debt Service**

Assuming 30 yr term financing at interest rate of 4.20% in program case, PV of the payment stream of 30 annual payments @ interest rate of **4.20%** = 11,572,549 Principle Amount Financed FY2007 = 195,341,712

Debt service payments principle amount of = 195,341,712 30 annual payments, @ **4.25%** = 11,642,023 **= 7(b)(2) Case Debt Service**

Interest rate of 4.25% is per the Financing Study prepared by the PFM Group, Appendix A to WP-07-FS-BPA-14 at Table A, page 4.

Note 2 - 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-07 Supplemental Rate Case
Section 7(b)(2) - Resource Stack - Updated Cost Projections for Idaho Falls Hydro Project
Purchase Power Contract
FY2007-2008 Lookback Analysis - Resource Stack

Idaho Falls Hydro Project - Revised Cost Projections:

7(b)(2) Case - Resource Stack Values:			FY2007-$$	FY1980-$$
Annual Power Purchase Cost	162,060	@ 36.62	$5,935,013	$2,615,043
Placed in service			1982	1982
Average Annual Energy Output/@ 18.5.0MWh[3]			162,060.00	162,060.00
Average Hourly Energy aMW[3]			18.50	18.50
Cost per MWh			$36.62	$16.14

* Inflator conversion factor of 2.269566 was used to convert the resource cost data that is expressed in 2007 dollars to 1980$$. GDP - Deflator to convert 2007$$ to 1980$$ = 2.269566

Note 1 - Projected Contract Pricing MWh is at the average purchase power rate paid during FY2005 and FY2006. The current power purchase contract has a contract cap rate of $39.05/MWh. The current contract expires on September 30, 2011. It is reasonable to expect the cost of this power purchase contract will exceed the value of $5,935,013 (stated in 2007 dollars) during the later years of the rate test period from the time perspective of August 2008. This was not the expectation however at the time the WP-07-FS rate case was finalized in July of 2006.

Note 2 - 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 Purchase Power Contract with Idaho Falls Power

	Projected Contract Price FY2005-2006 - Average	GDP Deflator 2007$$ Conversion	2007$$ Real Pricing	Program Case Revenue Requirement Amounts @ 18.5 aMW	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2007	$36.62	1.000000	36.62	6,436,000	5,935,013	(500,987)
FY 2008	$36.62	1.021026	35.87	6,436,000	6,059,803	(376,197)
FY 2009	$36.62	1.042052	35.14	6,436,000	6,184,592	(251,408)
FY 2010	$36.62	1.061396	34.50	6,436,000	6,299,399	(136,601)
FY 2011	$36.62	1.082422	33.83	6,436,000	6,424,189	(11,811)
FY 2012	$36.62	1.105130	33.14	6,436,000	6,558,961	122,961
FY 2013	$36.62	1.126997	32.50	6,436,000	6,688,742	252,742
		Average	34.515209			(901,300)

Historical Generation / Purchases from IFP:

Year	Average Annual Energy - MWh	Capacity Factor @18.5 aMW	Total Dollars Paid to IFP	Average Rate paid to IFP with Collar / $/MWh
2002	111,254	68.65%	$3,252,009	$29.23
2003	113,443	70.00%	$3,954,660	$34.86
2004	110,924	68.45%	$4,110,379	$37.06
2005	119,433	73.70%	$4,470,753	$37.43
2006	140,770	86.86%	$5,041,195	$35.81
5-Year Average	119,165	73.53%		$34.88
FY2005-2006 Average	130,102	80.28%		$36.62

March 2007 BPA White Book Resource Values, Table 5, page 23

Date in Service	1982
Capacity Peak MW	18
Firm energy aMW	19
Total Annual Energy @ 18	157,680
Total Annual Energy @ 19	166,440
LARIS average @ 18.5 aMW	162,060

Section 7(b)(2) - Resource Stack - Updated Cost Projections for Nine Canyon Wind Project
FY2007-2008 Lookback Resource Stacks
Operating Budget / Funding Requirements

7(b)(2) Resource Stack Amounts -			
Portions Not Dedicated to Native Load:		**FY 2007$$**	**FY 1980$$**
Revenue Requirement Allocation to Non-Dedicated Portions = 40.65%		$2,834	$1,249
Share of total net generation (MWh)		71,265	71,265
Average energy per hour (aMW) / Name Plate rating times Capacity Factor		8.14	8.14
Share of name plate rating		25.90	25.90
Cost of Power ($/MWh)		$39.77	17.52
GDP - Deflator to convert 2007$$ to 1980$$ =	2.269566		

	($ 000)			
	Percent	**FY2006 Budget**	**FY2007 Budget Projection**	**FY2007 Non-Dedicated Portion**
				0.4065
Inflation Adjustment			1.0287	
Projected Costs of Operations:				
Labor & Overheads	9.66%	667	686	279
Equipment / materials / Services	9.63%	665	684	278
Insurance	2.61%	180	185	75
Lease Payments	3.66%	253	260	106
Tx Costs	0.90%	62	64	26
Contingency / Fees	2.90%	200	206	84
Other Costs	4.17%	288	296	120
Taxes	0.51%	35	36	15
Subtotal Operating Costs	34.03%	2,350	2,417	983
Depreciation	52.14%	3,600	3,600	1,464
Interest Financing Costs	61.51%	4,247	4,247	1,727
Gross Generation Costs	147.68%	10,197	10,264	4,173
Renewable Energy Production Incentive Credits (REPI)	-37.90%	(2,617)	(2,617)	(1,064)
Net Generation Costs	109.78%	7,580	7,647	3,109
Net Generation Costs per above	109.78%	7,580	7,647	3,109
Less Depreciation Expense	-52.14%	(3,600)	(3,600)	(1,464)
Capital requirements	0.16%	11	11	4
Bond Retirement / Trustee Fees	47.34%	3,269	3,269	1329
Interest Income	-5.14%	(355)	(355)	(144)
Net Revenue Requirement	100.00%	6,905	6,972	2,834
Check				2,834
Total Net Generation (MWh)		175,300	175,300	71,265
Cost of Power ($/MWh)		$39.39	$39.77	$39.77
Capacity Factor			0.31415095	0.31415095

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Section 7(b)(2) - Resource Stack - Updated Cost Projections for Nine Canyon Wind Project
FY2007-2008 Lookback Resource Stacks
Operating Budget / Funding Requirements

Energy NW 63.71 MW Nine Canyon wind power project allocations - for FY2007-2008 Lookback.

Nine Purchasers	Phase 1 MW Share	Phase 2 MW Share	Total MW Share	% total	Resource Dedicated to native Load?
PUD No. 1 of Benton County	3.01	0.00	3.01	4.72%	Yes[1]
PUD No. 1 of Chelan County	6.01	1.95	7.96	12.49%	Yes
Cowlitz Co PUD (assigned from ENW)	2.00	0.00	2.00	3.14%	Yes
PUD No. 1 of Douglas County	3.01	6.80	9.81	15.40%	Quasi[2]
Franklin Co PUD	2.01	0.00	2.01	3.15%	NO[3]
PUD No. 1 of Grays Harbor	6.01	1.95	7.96	12.49%	NO[3]
PUD No. 1 of Lewis County	1.00	0.00	1.00	1.57%	Yes
PUD No. 1 of Okanogan County	12.03	3.90	15.93	25.00%	NO[3]
PUD No. 2 of Grant County	12.03	0.00	12.03	18.88%	Quasi[2]
PUD No. 3 of Mason County	1.00	1.00	2.00	3.14%	Yes
Total	48.11	15.60	63.71	100%	

Amount of preference owned resource that is NOT dedicated to serve regional preference loads. = 40.65%

Note 1 - 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 2 - 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 3 - Confirmed that the resource was not dedicated to this utilities native load through their BPA Account Executive.

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2007-2008 Lookback Analysis Resource Stack

7(b)(2) Case - Resource Stack Values:	**FY2007-$$**	**FY1980-$$***
Total O&M - FY 2007 Non-dedicated COU & Marketer Projection = 20.2aMW *$16.0442/MWh*8,760 hour /year	2,839,053	1,250,923
Cost per MWh	$16.04	$7.07
Capital Investment - Projected Net Utility Plant FY 2007 per Financial Statement	$189,610,161	NA
Life	70-100 years	70-100 years
Placed in service	1959	1959
Non-dedicated COU & Marketer average hourly energy (aMW) seven-year average FY2007-2013	20.2	20.2
Average Annual Energy Output/@ 17.7MWh	176,952	176,952

* Deflator conversion factor of 2.269566, was used to convert the resource cost data that is expressed in 2007 dollars to 1980 dollars. 2.269566

		Financial Statement Information (in whole dollars)			BPA Analyst Projected Operating Budget	**Grant's[6] Projected Operating Budget**	BPA Analyst Projected Operating Budget
GDP Inflation Factors Projections					1.017	1.017	1.021
		2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Revenues		32,064,057	30,810,541	30,707,299	34,600,000	44,000,000	46,000,000
Operating Expenses - See Notes 1, 2, and 4 below:							
Generation		11,636,471	10,122,746	10,402,512	10,579,355	7,243,491	7,395,604
Transmission		889,319	850,426	838,216	852,466	795,871	812,584
Administrative and General		6,897,861	6,570,905	6,106,684	6,210,498	10,823,737	11,051,035
Maintenance Expenses						5,653,207	5,771,924
Depreciation Expenses		4,613,571	3,681,788	5,078,184	5,157,659	5,334,210	5,513,763
Taxes		856,948	783,116	801,631	815,259	850,000	867,850
Other Operating Costs					1,240,681		
Total Operating Expenses	*	24,894,170	22,008,981	23,227,227	24,855,917	30,700,516	31,412,761
Net Operating Income		7,169,887	8,801,560	7,480,072	9,744,083	13,299,484	14,587,239

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Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2007-2008 Lookback Analysis Resource Stack

Non Operating Revenues and (Expenses)							
Interest Income (Expense)/Gains on Debt Retirements	*	967,727	451,766	338,167	300,000	1,670,598	1,500,000
Interest on Proposed New Debt	*					(3,287,457)	(3,300,000)
Interest on Long-Term Debt - See Note 3	*	(8,253,381)	(8,029,995)	(7,575,817)	(9,050,531)	(8,792,613)	(11,850,662)
Amortization of Debt Expense and Discounts		(614,378)	(695,559)	(694,445)	(693,000)	(691,500)	(700,000)
Total Non Operating Expenses		(7,900,032)	(8,273,788)	(7,932,095)	(9,443,531)	(11,100,972)	(14,350,662)
Excess (Shortfall) of Revenues Over Cost of Services		(730,145)	527,772	(452,023)	300,552	2,198,512	236,577
Operating Costs Before Adjustments		32,179,824	29,587,210	30,464,877	33,606,448	41,109,988	45,063,423
(* Sum of numbers asterisks)							

Schedule of Power Costs:	Financial Statement Information (in whole dollars) **2002**	**2003**	**2004**	BPA Analyst Projected Operating Budget **2005**	**Grant's Projected Operating Budget 2006**	BPA Analyst Projected Operating Budget **2007**
Operating Costs Before Adjustments - sum of *	32,179,824	29,587,210	30,464,877	33,606,448	41,109,988	45,063,423
Budget/Operating Cost Adjustments:						
Less Extraordinary maintenance paid by Reserve Funds	(76,008)	(68,630)	0	0	0	0
Less Depreciation Expense	(4,613,571)	(3,681,788)	(5,078,184)	(5,157,659)	(5,334,210)	(5,513,763)
Less 15% of prior year second series debt installments	(1,985,010)	(1,926,646)	(1,952,249)	(1,900,317)	(2,079,116)	(2,899,511)
Plus (less) exclusion of interest on special funds	39,934	(54,716)	(146,826)	(149,322)		(152,458)
Plus capitalized interest	45,928	0	268,747	233,930	0	241,951
Plus Principal and sinking fund payments on debt - See Note 4 below.	4,545,000	4,985,000	5,195,000	5,195,000	7,250,000	7,350,000
Plus 15% of interest and sinking fund installments	1,926,646	1,952,249	1,955,935	2,171,919	2,899,511	2,916,392
Bond issuance costs	1,314	17,861	0	0		0
Net Costs Chargeable to Power Purchasers	32,064,057	30,810,540	30,707,300	33,999,999	43,846,173	47,006,035

	2005	2006	2007
Projected Owners Operating Budget escalated for inflation - whole dollars	$33,999,999	$43,846,173	$47,006,035
Average Firm Energy Output (PNW L&R Study #30) (334.45MW) times the number of hours in a year (8760)	2,929,782	2,929,782	2,929,782
Projected Project Cost per MWh using Project Owners Debt Service	**$11.6050**	**$14.9657**	**$16.0442**

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2007-2008 Lookback Analysis Resource Stack

Selected Balance Sheet Items - Priest Rapids Hydroelectric Project:

(in whole dollars)

	2002	2003	2004	2005	2006	2007
Electric Plant Gross (Dam placed in service 1970)	$248,319,424	$250,995,893	$257,882,972	266,710,518	275,688,132	284,818,366
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	8,977,614	9,130,234	9,321,969
Accum. Deprec. & Amortization (15-95 year lives)	(107,042,152)	(110,725,130)	(115,853,195)	(121,010,854)	(126,345,065)	(131,858,827)
Net Electric Plant (Note 3 of 2003 & 2004 F.S.)	148,245,289	153,040,452	153,443,899	157,263,854	161,059,877	164,868,083
Deferred relicensing costs	15,969,761	21,479,506	25,926,488			
Unamortized debt expense	1,747,505	2,084,600	1,853,557			
Other Deferred Charges and other assets	9,306	0	0			
Total Non Current Assets	165,971,861	176,604,558	181,223,944			
Restricted Assets Current	30,208,013	42,056,984	32,527,571			
Current and Accrued Assets	16,200,038	7,951,490	8,182,286			
Total Current Assets	46,408,051	50,008,474	40,709,857			
Total Assets	$212,379,912	$226,613,032	$221,933,801			
Long-Term Debt-net of discounts	$145,591,449	$172,146,382	$167,414,785			
Current portion of long-term debt	4,545,000	4,985,000	5,195,000			
Current & Accrued Liabilities	22,860,256	9,570,671	9,865,060			
Other Liabilities						
Total Liabilities	172,996,705	186,702,053	182,474,845			
Retained Earnings - restricted for debt service	6,338,804	6,940,349	7,178,763			
Retained Earnings - restricted other	6,000,000	6,000,000	0			
Retained Earnings - unrestricted	27,044,403	26,970,630	32,280,193			
Total Liabilities & Retained Earnings	$212,379,912	$226,613,032	$221,933,801			

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Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation
FY 2007-2008 Lookback Analysis Resource Stack

Notes:

1. The financial information for the years 2002, 2003, and 2004 was from Grant County PUD No. 2's audited financial statements, 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 2005-2007 were based on the 2004 and prior years' audited reports as adjusted for the GNP Price Deflator Inflation Projection obtained from DRI. Specific projections for depreciation expense and debt service were based on the 2004 audited financial statement's notes and other supplementary information.

3. Debt Service Information
The actual interest (a) and principal (b) on the Priest Rapids Bonds for the years 2002-2004 was taken from the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2005-2007 on the Priest Rapids Revenue Bonds was obtained from Note 5 of the 2004 financial statements (p103), Scheduled debt service requirements. A portion of the information for 2002-2004 was from the Schedules of Power Costs Chargeable to Power Purchasers. The projections for capitalized interest expense for 2005-2007 was computed using an assumed interest rate of 2.65% applied to the balance of construction work in progress at the beginning of the year.

	2002	2003	2004	2005	2006	2007
Actual/Projected Interest on Priest Rapids Bonds (a)	8,052,724	7,511,045	7,683,777	9,284,461	9,030,520	8,792,613
Less Capitalized interest expenses	(45,928)	0	(268,747)	(233,930)	(237,907)	(241,951)
Adjustment in interest expense	246,585	518,950	160,787	0	0	0
Interest on proposed new debt (a)					3,287,457	3,300,000
Total Interest Expense per operating statement projections	8,253,381	8,029,995	7,575,817	9,050,531	12,080,070	11,850,662
Actual/Projected Principal payments on Priest Rapids Bonds (b)	4,270,000	4,545,000	4,985,000	5,195,000	7,250,000	7,350,000
Total Debt Service (a) + (b)	12,322,724	12,056,045	12,668,777	14,479,461	19,567,977	19,442,613
15% of Debt Service Requirements			1,900,317	2,171,919	2,899,511	2,916,392

4. Under the Power Sales Contracts (See Note 1, accounting policies, revenue recognition), the power purchasers of the project pay all expenses and costs associated with producing and delivering the power, plus 115% of their share of the amounts required for debt service payments. Depreciation, extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and Construction Fund and are not considered costs of producing and delivering power for this purpose.

5. Projection of depreciation expense is based on a 2% recovery rate applied to the plant in service balance at the beginning of the year. Electric plant financial information can be found at Note 3 of the Priest Rapids Project's financial segment information (pg. 99 of 2004 F.S.).

6. BPA sent a data request to Grant County PUD #2 dated 5/11/2005 for the projected operating costs of the Priest Rapids Hydroelectric project for the years 2006-2013. Grant County PUD#2 did not respond to the data request. BPA sent a projection of operating costs to Grant County PUD#2 on September 19, 2005, and asked it to please review and make corrections to the projections. Grant County PUD #2 responded in an email on 9/28/05 that its projected operating costs for Priest Rapids project for FY2006 were $43.8 million dollars per year. The projected budget numbers received from Grant for FY2006 are reflected in the spreadsheet.

Grant's Priest Rapids Allocation for 2007-2013
Remainder of Data for 2009-2013 is BPA's Table A-20 Priest Rapids Allocation
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case for 2007- 2008 / 2007 Supplemental 2009 - 2013

Priest Rapids Energy in Megawatts		**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Priest Rapids Dam, Project Owner = Grant County PUD, FERC License Exp. 10/31/2005,								
New Purchaser Agreements became effective 11/01/2005.								
Priest Rapids								
30 AVWP - Avista Share		11.5	11.5	12.0	14.0	13.0	13.0	13.0
31 COPD - Cowlitz County PUD Share		5.3	5.3	5.6	8.8	9.9	9.9	9.9
32 CWPC - Clear Water PUD Share	**	0.4	0.4	0.4	0.4	0.4	0.4	0.4
33 EWEB - Eugene Water & Electric Share		3.2	3.2	3.4	4.0	3.7	3.6	3.6
34 FGRV - Forest Grove Share		1.2	1.2	1.3	1.5	1.6	1.6	1.6
35 FREC - Fall River Electric Coop. Share	**	0.5	0.5	0.5	0.5	0.5	0.5	0.5
36 GCPD - Grant County PUD Share		215.8	216.2	229.0	202.0	213.0	215.0	216.0
37 ICLP - Idaho City Light PUD Share	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
38 KITT - Kittitas County PUD Share		1.0	1.0	1.0	0.7	0.5	0.5	0.5
39 KOOT - Kootenai Share	**	0.7	0.7	0.7	0.7	0.7	0.7	0.7
40 LREC - Lost River Electric Cooperative Shar	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
41 LVE - Lower Valley Electric Coop. Share	**	0.9	0.9	0.9	0.9	0.9	0.9	0.9
42 MCMN - McMinnville Share		1.2	1.2	1.3	1.5	1.6	1.6	1.6
43 MTFR - Milton Freewater Share		1.2	1.2	1.3	1.5	1.6	1.6	1.6
44 NLEC - Northern Lights Electric Coop. Shar	**	0.6	0.6	0.6	0.6	0.6	0.6	0.6
45 PGE - Portland General Electric Share		26.2	26.3	28.0	33.0	30.0	29.0	29.0
46 PPL - Pacific Power and Light Share		26.2	26.3	28.0	33.0	30.0	29.0	29.0
47 PSE - Puget Sound Energy Share		15.1	15.1	16.0	19.0	17.0	17.0	17.0
48 RREC - Raft River Electric Coop. Share	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
49 SCL - Seattle City Light Share		1.9	1.9	2.0	14.0	16.7	16.0	16.0
50 SLEC -Salmon River Electric Coop. Share	**	0.1	0.1	0.1	0.1	0.1	0.1	0.1
51 TPU - Tacoma Public Utilities Share		14.2	14.2	15.0	18.0	16.7	16.0	16.0
52 UNEC - United Electric Coop. Share	**	0.2	0.2	0.3	0.3	0.3	0.3	0.3
53 UNKMKT - Unknown Market Purchaser Sha	**	22.8	22.9	22.0	14.0	11.0	11.0	11.0
54 Priest Rapids After Encroachment		350.9	351.5	369.8	368.9	370.2	368.6	369.7
54 and Canadian Entitlement								
COUs not Dedicated to Rgional Loads and Market Purchaser Allocations - **		26.6	26.7	25.9	17.9	14.9	14.9	14.9
Other Power Allocations		324.3	324.8	343.9	351.0	355.4	353.8	354.8
TOTAL		350.9	351.5	369.8	368.9	370.2	368.6	369.7

Non-dedicated COUs and
Market Purchaser Energy -
Seven Year Average Allocation FY2007-2013 = 20.2 Percent of Total Generation = 5.56%
Seven Year Total Power Generation Average FY2009-FY2013 = 364.2
Non-dedicated COUs and
Market Purchaser Energy -
Five Year Average Allocation FY2009-2013 17.7 Percent of Total Generation = 4.78%
Five Year Total Power Generation Average FY2009-FY2013 = 369.4

Priest Rapids Allocation Percentages	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
COUs not Dedicated to Rgional Loads and Market Purchaser Allocations - **	7.59%	7.59%	7.00%	4.84%	4.01%	4.03%	4.02%
Other Power Allocations	92.41%	92.41%	93.00%	95.16%	95.99%	95.97%	95.98%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Non-dedicated COUs and
Market Purchaser Energy -
Seven Year Average Allocation FY2007-2013 **5.56%**
Non-dedicated COUs and
Market Purchaser Energy -
Five Year Average Allocation FY2009-2013 **4.78%**

WP-07 Supplemental Rate Case
Section 7(b)(2) Resource Stack - Wauna CoGen Resource for FY 2007-2013
Purchase Power Contract
FY 2007-2008 Lookback Resource Stack

Wauna CoGeneration Resource - Revised Cost Projections:

7(b)(2) Case - Resource Stack Values:	**FY2007-$$**	**FY1980-$$**
Annual Power Purchase Cost	$10,966,556	4,832,006
Placed in service	1996	1996
Average Annual Energy Output/@ 23.0MWh[2]	201,480	201,480
Cost per MWh	$54.43	$23.98

* Inflator conversion factor of 2.269566 was used to convert the resource cost data that is expressed in 2007 dollars to 1980 dollars. 2.269566

Note 1 - After a resource is chosen by the rates model, its annual costs (stated in 1980 "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 was adjusted 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.

Note 2 - 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 Purchase Power Contract with Western Generation Agency - Wauna Cogeneration Project - Contract Pricing Schedule

	Contract Price - Nominal Pricing	GDP Deflator 2007$$ Conversion	2007$$ Real Pricing	Program Case Revenue Requirement Amounts @ 23 aMW	7(b)(2) Case Escalated Price Projections	7(b)(2) Case Over (Under) Program Case
FY 2007	56.16	1.000000	56.16	11,428,000	10,966,556	(461,444)
FY 2008	57.13	1.021026	55.95	11,634,000	11,197,139	(436,861)
FY 2009	58.14	1.042052	55.79	11,249,900	11,427,722	177,822
FY 2010	59.21	1.061396	55.79	11,462,700	11,639,859	177,159
FY 2011	60.33	1.082422	55.74	11,732,500	11,870,442	137,942
FY 2012	61.51	1.105130	55.66	11,922,500	12,119,470	196,970
FY 2013	62.75	1.126997	55.68	12,169,500	12,359,276	189,776
		Average	55.8237106			(18,635)
Program Case Price Adjustment			(1.393711)			
7(B)(2) Case Pricing - 2007$$			54.43			

Historical Generation / Purchases from Wauna Project:

W/P Reference		Average Hourly Energy - MWh	Loads & Resources Study[2] Firm Energy - (aMW)
4	FY 1999	25.82575	
4	FY 2000	22.81016	
4	FY 2001	22.29335	23
3	FY 2002	23.90805	
3	FY 2003	22.26203	
3	FY 2004	23.33532	
2	FY 2005	21.58635	
	Average	23.14585857	

11. BACKCAST OF IOU ASCS, FY 2007-2008

11.1 FY 2007-2008 Backcast Overview

This chapter estimates the annual Average System Cost (ASC) determinations that would have been made had the investor-owned utilities (IOUs) submitted ASC filings with BPA for 2007-2008. The backcast ASC determinations described in this chapter generally follow the same construct described in Chapter 7 of this study for FY 2002-2006.

No ASC filings were made with BPA, and no filings are expected during FY 2007 or FY 2008 for the purpose of establishing an ASC. Such filings would have been made under an active Residential Exchange Program (REP) had BPA and the IOUs not executed REP Settlement Agreements. Consequently, BPA must estimate annual ASCs in order to determine what REP payments the IOUs would have received for this period under an active REP. This chapter of the Lookback Study describes how these ASC determinations were made and presents the results. BPA calculated annual ASCs for Avista, Idaho Power, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy for FY 2007 and FY 2008. Public utilities are not included in this analysis.

To estimate these ASCs, BPA completed a detailed review of financial and operations data of each IOU for 2006 and escalated the 2006 costs and loads to 2007 and 2008. The results of this review establish an annual "backcast" ASC determination for each utility. This chapter focuses on the backcast determination for FY 2007-2008 only. *See also* Chapter 7 of this Study for 2002-2006 backcast determinations.

11.2 Backcast ASC Determination Process

As described in Chapter 7, "backcast" is BPA's term for ASCs that BPA believes would have been determined had the REP been operational during the WP-07 rate period. A backcast ASC is based primarily on review and analysis of 2006 FERC Form 1 data. These data were entered into the updated 1984 ASC Cookbook model, as described in Chapter 7, to establish estimates of ASCs for each IOU for the WP-07 rate period.

BPA complied with the 1984 ASCM when it prepared the backcast ASCs with one exception: use of FERC Form 1 data as the primary source of data instead of jurisdictional rate orders from state regulatory commissions. Other than use of FERC Form 1 data, BPA complied with the 1984 ASCM for inclusion and functionalization of costs in the ASC Cookbook model. Use of FERC Form 1 data as the primary source of data for the ASC Cookbook model for the backcast resulted in a consistent and uniform development of the ASCs for the IOUs. The FERC Form 1 data populated the ASC Cookbook, an Excel-based computer modeling tool. Once populated with a utility's financial and operating data, the ASC Cookbook separated, or "functionalized," the total costs and revenues into production, transmission, and distribution functions; *i.e.*, to functions that may be exchanged (exchangeable costs) and to those that may not be exchanged.

A two-step process was used to estimate the backcast ASCs for 2007 and 2008. First, a "base year" ASC was calculated using the 2006 FERC Form 1 data for each of the IOUs. This base year ASC includes all the changes discussed in Chapter 7. Second, the ASC Forecast Model was used to escalate the 2006 base year to estimate ASCs for each IOU for 2007 and 2008.

The model is designed to forecast the costs a utility will incur to meet load growth. It forecasts purchased power, sales for resale, fuel cost and non-fuel/purchase costs (NFPC). The ASC Forecast Model uses inflation escalators, gas and coal price forecasts, and electric market price forecasts to escalate base ASC costs. In addition, the ASC Forecast Model estimates the cost of serving forecast load growth.

11.3 2006 Base Year ASC

The 2006 backcast ASC was used to establish the base year ASC, as described in Chapter 7. Table 11.1 below shows the 2006 base year ASCs and exchange load.

Table 11.1
2006 Base Year ASCs

	ASC ($/MWh)	Exch. Load (MWh)
Avista	44.40	3,756,579
Idaho Power	27.86	7,038,389
NorthWestern Energy	52.62	898,218
PacifiCorp (PNW)	41.06	9,251,568
PacifiCorp (Oreg.)	42.07	6,080,289
PacifiCorp (Wash.)	39.66	1,838,386
PacifiCorp (Idaho)	38.61	1,332,893
Portland General	49.72	8,049,271
Puget Sound	55.32	11,674,554

11.4 Contract System Load and Exchange Load

Contract System Load is the total consumer end-use load of a utility plus 5 percent distribution losses less any NLSLs. See Section 7.4.4. BPA load forecasts for 2007 and 2008 were used for Contract System Load and exchange loads. The Contract System Load forecasts are shown in Table 11.2. Table 11.3 shows exchange load forecasts.

Table 11.2
Forecast Contract System Loads
(gigawatt hours)

	2006	2007	2008
Avista	9,165	9,331	9,511
Idaho Power	14,251	14,625	14,962
NorthWestern	7,370	7,432	7,517
PacifiCorp (PNW)	22,138	22,083	22,359
PacifiCorp-OR	14,608	14,422	14,600
PacifiCorp-WA	4,374	4,462	4,517
PacifiCorp-ID	3,498	3,541	3,585
Portland General	19,331	20,381	20,605
Puget Sound	22,146	22,283	22,563

Table 11.3
Forecast Exchange Loads
(gigawatt hours)

	2006	2007	2008
Avista	3,757	3,824	3,897
Idaho Power	7,038	7,218	7,380
NorthWestern	898	951	962
PacifiCorp (PNW)	9,252	9,169	9,282
PacifiCorp-OR	6,080	5,977	6,051
PacifiCorp-WA	1,838	1,855	1,878
PacifiCorp-ID	1,333	1,336	1,353
Portland General	8,049	8,286	8,378
Puget Sound	11,675	11,747	11,894

11.5 Forecast Contract System Cost

Contract System Cost includes Non-Fuel and Purchased Power Costs (NFPC), fuel costs, purchased power, and sales for resale. The 2006 base year NFPCs are escalated by inflation. A separate escalator is used to project the 2006 base year natural gas costs. Coal costs are assumed to increase at 0.5 percent annually. Table 11.4 shows updated escalation rates used in the ASC Forecast Model. Purchased power and sales for resale are forecast as described below.

Table 11.4
Inflation Rates and Price Forecasts

	2007	2008
Inflation Rates	2.90%	3.30%
Electricity Price Forecast	50.11	62.89
Gas Price Forecast	6.34	8.58

11.5.1 Forecast Purchased Power

Forecasts of a utility's purchased power costs are a function of historical purchases and growth of the utility's total retail load. The ASC Forecast Model assumes that increases in total retail load will be met with market purchases. The increase in total retail load is added to the quantity of the utility's purchased power and priced at the projected market price of electricity for each year of the forecast period.

In the FERC Form 1, utilities separate purchased power by the type and length of the purchase and also report any adjustments. The ASC Forecast Model distinguishes between long-term and short-term purchased power. The FERC Form 1 reports the following categories of purchased power:

Requirements service (RQ) – service that the supplier plans to provide on an ongoing basis (*i.e.*, the supplier includes project load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers;

Long-term firm service (LF) – service for five years or longer, cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (*e.g.*, the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service);

Intermediate-term firm service (IF) – the same as LF service expect that "intermediate-term" means longer than one year but less than five years;

Long-term service from a designated generating unit (LU) – LF service where the availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit;

Intermediate-term service from a designated generating unit (IU) – the same as LU service except that “intermediate-term” means longer than one year but less than five years;

Short-term service (SF) – all services where the duration of each period of commitment for service is one year or less;

Other services (OS) – services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the length of the contract and service from designated units of less than one year;

Exchanges of electricity (EX) – transactions involving a balancing of debits and credits for energy, capacity, etc., and any settlements for imbalanced exchanges;

Not applicable (NA) – PacifiCorp used NA for not applicable: adjustment for inadvertent interchange; and

Out of period adjustments (AD) – accounting adjustments or true-ups for service provided in prior reporting years.[3]

Long-term purchases include the RQ, LF, LU, IF, and IU categories. The quantity of long-term purchases is assumed to be constant over the forecast period. The price at which the power is purchased escalates at the rate of inflation, using the average cost of long-term purchases in 2006 as the base.

Short-term purchases include the OS, SF, AD, NA, and EX categories. The quantity of short-term purchases (MWhs) for 2007 and 2008 is set equal to the average of short-term purchases from 2002-2006. The forecast then holds the quantity of short-term wholesale purchases

[3] FERC Form 1 Account 447, Page 310, and Account 555, Page 326.

constant through the forecast period and prices them at BPA's forecast market price of electricity for the years 2007-2013.

11.5.2 Sales for Resale Revenue Credit

In the FERC Form 1, utilities separate sales for resale by the type and length of the sale and also report any adjustments. The ASC Forecast Model distinguishes between long-term and short-term sales for resale. The FERC Form 1 reports the same categories for sales for resale as for purchased power.

The ASC forecast assumes that the quantity of long-term and intermediate-term firm sales is constant for 2007 and 2008 and that revenue from such sales escalates at the rate of inflation. The quantity of long-term sales in the forecast period is equal to the average of long-term sales from 2002-2006.

Short-term sales include the OS, SF, AD, NA, and EX categories. The quantity of short-term sales (MWhs) for 2007 and 2008 is equal to the average of short-term sales from 2002-2006. The revenue from short-term sales is equal to the quantity of short-term sales times BPA's forecast market price of electricity for the years 2007 and 2008.

11.6 New Large Single Loads

Determination of the cost of resources used to serve NLSL(s) and the estimate of NLSL(s) for each utility for 2007 and 2008 can be found at the end of the Supplemental Final Lookback Documentation, WP-07-FS-BPA-08B.

11.7 Contract System Cost

The ASC forecast model separately calculates fuel costs (FC), NFPC, purchased power cost (PP), and sales for resale revenue (SRR).

The Annual Fuel Cost is calculated by adding annual forecasted Coal Cost to annual forecasted Natural Gas Cost:

$$\text{Coal Costs}_{2007} = \text{Coal Costs}_{2006} * (1 + 0.05\%)$$

$$\text{Natural Gas Cost}_{2007} = \text{Natural Gas Cost}_{2006} * (\text{NG Price}_{2007} / \text{NG Price}_{2006})$$

$$FC_{2007} = \text{Coal Costs}_{2007} + \text{Natural Gas Cost}_{2007}$$

The NFPC are Production and Transmission costs, excluding fuel and purchased power cost before sales for resale revenues are subtracted. Annual forecast costs are calculated using the 2006 base value.

$$NFPC_{2006} = (\text{Production}_{2006}\ \text{Costs} + \text{Transmission}_{2006}\ \text{Costs}) + \text{Sales for Resale}_{2006} - FC_{2006} - PP_{2006}$$

$$NFPC_{2007} = NFPC_{2006} * (1 + \text{inflation}_{2007})$$

The annual purchased power cost is calculated as follows: Short-term purchased power costs $_{2007}$ = (Average $_{2002\text{-}2006}$ MWh purchases * BPA Market Price $_{2007}$) + (Long-term purchased power costs$_{2006}$ * (1+ escalator $_{2007}$))

The sales for resale revenue (SRR) is calculated as follows:

$$\text{Short-term sales}_{2007} = (\text{Average}_{2002\text{-}2006}\ \text{MWh sales} * \text{BPA Market Price}_{2007}) + (\text{Long-term sales}_{2006} * (1 + \text{escalator}_{2007}))$$

The ASC Forecast Model calculates Contract System Cost as follows:

$$\text{Contract System Cost}_{2007} = FC_{2007} + NFC_{2007} + PP_{2007} - SRR_{2007} - \text{NSLS costs}_{2007}$$

A similar process was used to calculate Contract System Cost for 2008.

11.8 2007–2008 Backcast ASCs

ASC backcasts are calculated by dividing Contract System Cost by Contract System Load. The 2007-2008 backcast ASCs are shown in Table 11.5. The detailed ASC Forecast Model for each of the IOUs is provided in the Lookback Documentation, WP-07-FS-BPA-08A.

Table 11.5
2007 and 2008 Backcast ASC Determinations

	2007		2008	
	ASC ($/MWh)	Exch. Load (MWh)	ASC ($/MWh)	Exch. Load (MWh)
Avista	47.36	3,824,029	51.10	3,897,357
Idaho Power	31.85	7,218,346	34.02	7,380,466
NorthWestern	51.47	951,068	53.13	961,972
PacifiCorp-PNW	40.54	9,168,719	42.20	9,281,739
PacifiCorp-OR	41.97	5,977,338	43.65	6,051,019
PacifiCorp-WA	38.31	1,855,179	39.80	1,878,047
PacifiCorp-ID	37.38	1,336,202	39.05	1,352,673
Portland General	46.75	8,286,384	52.29	8,377,545
Puget Sound	51.56	11,746,838	56.63	11,894,349

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PART THREE: LOOKBACK RESULTS

Chapter 12: Lookback Results Introduction

Chapter 13: Actual and Projected Settlement Benefits Paid to IOUs for FY 2002-2008

Chapter 14: Residential Exchange Benefits Under the Traditional Residential Exchange Program

Chapter 15: Lookback Amounts, Recovery and Return

12. LOOKBACK RESULTS INTRODUCTION

12.1 Introduction

Part Three of the Lookback Study presents BPA's calculations of Lookback Amounts based on the information presented in Part One and Part Two of this Study. It further presents BPA's plan to return the Lookback Amounts to COUs.

The Lookback Amount for each IOU is the difference between the amounts paid pursuant to the REP Settlement Agreements and the amount the IOU would have received if it had signed a Residential Purchase and Sale Agreement (RPSA) and participated in the REP.

Chapter 13 establishes the annual amounts that each IOU received pursuant to its REP Settlement Agreement, including any amounts paid pursuant to an LRA.

Chapter 14 presents the annual amounts that each IOU would have received pursuant to an RPSA using the ASCs and PF Exchange rates developed in Parts One and Two.

Chapter 15 combines the results of Chapter 13 with the results of Chapter 14 to compute the annual Lookback Amounts for each IOU, subject to certain provisions regarding deemer balances and LRA payments. Chapter 15 further discusses BPA's plans for recapturing the Lookback Amounts from the IOUs and returning these amounts to COUs.

13. ACTUAL AND PROJECTED SETTLEMENT BENEFITS PAID TO IOUS FOR FY 2002-2008

13.1 Actual Settlement Benefits Paid to the IOUs

IOUs received $2,097,328,143 in REP settlement benefits from BPA from November 2001 (for October 2001) through April 30, 2007 (March 2007 payment was paid in April 2007). *See* Lookback Documentation, WP-07-FS-BPA-8A, Tables 13.1.1 through 13.1.7. These REP settlement benefits include all payments or power deliveries made under the 2000 REP Settlement Agreements and their various related amendments. First, BPA included the payments identified in the REP Settlement Agreements themselves. BPA also included the payments made under the Conservation and Renewables Discount (C&RD) and the Conservation Rate Credit (CRC) and payments made through the 2004 Amendments to the Settlement Agreements, the Load Reduction Agreements (LRAs) BPA executed with PacifiCorp and Puget Sound Energy, and the Reduction of Risk Discount. In addition, the total REP settlement benefits received by PGE include the value of the power sale at the Residential Load (RL) rate under the terms of PGE's Settlement Agreement for FY 2002-2006.

During the implementation of the REP Settlement Agreements and their amendments, BPA conducted a Compliance Oversight Function to help ensure that the REP settlement benefits that BPA paid the IOUs were actually paid to their residential and small farm customers. BPA prepared an annual accounting summary of the actual monthly BPA Power Bill components for each IOU. All cash payments, with the exception of the amounts paid through the C&RD and the CRC, and including the value of the power sale to PGE, were included in this annual accounting for the Compliance Oversight Function. The C&RD and CRC payments were not included in this annual accounting because these payments were not passed on to the residential and small farm customers of the IOUs. Adjustments were made until both BPA and the IOU agreed with the results, and each IOU confirmed the accuracy of BPA's accounting summary.

Annual certification statements were prepared by each IOU that summarized the beginning balance in the "balancing account," the amount of benefits received from BPA, the amount that was distributed to eligible residential and small farm customers, and the ending balance in the balancing account for the contract year. The contract year was the same as BPA's fiscal year.

The balancing account reflected the balance owed to residential and small farm consumers when the amount of credits distributed during the year was less than the amount of settlement benefits received for the year. The balancing account reflects any advances made by the IOU when the amount of settlement benefits paid to residential and small farm consumers exceeded the amount of benefits received from BPA for the year.

In addition, the benefit payments were required to be placed in interest-bearing accounts until they were paid to eligible consumers. Some IOUs and their state commissions also allowed interest earned to be retained by the IOU when the level of benefits paid to retail customers exceeded the amount of Settlement benefits received from BPA.

The annual certification statements account for the interest owed customers and the interest kept by the IOU, if applicable. The annual certification statements contain the following affirmation statement: "By signing this certification, I affirm that all the information provided in this statement is true and correct to the best of my knowledge and belief." The annual accounting/certification statements for REP settlement benefits were signed by officers/officials (generally the Chief Financial Officer) of the IOUs.

After the settlement payments were suspended in May 2007, BPA prepared additional accounting summaries of other settlement benefits as follows: (1) the benefits paid to the IOUs through the C&RD and the CRC; (2) settlement benefits that were deferred, subsequent repayment of a portion of those deferrals along with accrued interest and the amounts written off by some IOUs, and the remaining balances owed PacifiCorp and Puget on their deferral balances; and (3) accountings that summarized the "reduction of risk" activity, balances after partial write-downs as of September 30, 2006, accrued interest, payments made during FY 2007, and the remaining balances owed PacifiCorp and Puget for the Reduction of Risk contract provisions. The accounting statements covering these additional settlement aspects were reviewed and certified by the IOUs and signed by an officer/official of the company subject to the above affirmation statement.

Table 13.1 summarizes the REP settlement benefits received by the IOUs prior to the suspension of payments in May 2008. Additional details can be found in Tables 13.1.1 through 13.1.7 in the FY 2002-2008 Lookback Documentation. (*See* FY 2002-2008 Lookback Documentation, WP-07-E-BPA-8A, Tables 13.2.1-13.2.7.) These tables provide a complete and accurate accounting of the total REP settlement benefits received by each IOU for FY 2002-2007.

As outlined in Note 1 to Table 13.1.1 in the FY 2002-2008 Lookback Documentation (WP-07-FS-BPA-08C), the amount of Portland General Electric (PGE) REP Settlement Benefits in the table below values the RL-02 Energy purchase based on the difference in the monthly average Mid-Columbia trading price and the purchase price of RL-02 Energy. This benefit amounted to $139,613,789 for the five-year period. PGE's annual accounting statement submitted to BPA valued the benefit of this energy at $187,131,671.

Table 13.1
REP Settlement Benefits – FY 2002-2006
($000)

	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007	Total
Avista	11,807	8,976	11,903	11,816	11,922	10,582	67,005
Idaho Power	14,567	12,041	15,927	15,800	15,949	15,893	90,178
NorthWestern Energy	3,105	2,376	3,161	3,135	3,168	1,995	16,941
PacifiCorp	117,064	109,402	121,318	120,986	120,981	46,285	636,036
Portland General Electric	28,358	46,830	69,608	89,131	99,594	39,467	372,987
Puget Sound Energy	172,779	150,916	179,103	178,614	178,614	54,155	914,181
Total	347,680	330,541	401,019	419,481	430,228	168,377	2,097,328

13.2 Projected Settlement Benefits that Would Have Been Paid to the IOUs for the Remainder of FY 2007 and FY 2008

Table 13.2 summarizes the projected REP settlement benefits that would have been paid to the IOUs for the remainder of FY 2007 and all of FY 2008. *See* FY 2002-2008 Lookback Documentation, WP-07-E-BPA-8A, Tables 13.2.1 through 13.2.7.

Table 13.2
REP Settlement Benefits – April 2007 through September 2008
($000)

	FY 2007	FY 2008	Total
Avista Corporation	10,561	21,005	31,567
Idaho Power	15,866	31,578	47,445
NorthWestern Energy	1,990	3,947	5,937
PacifiCorp	46,285	92,584	138,869
Portland General Electric	39,792	78,946	118,738
Puget Sound Energy	54,155	108,324	162,479
Total	168,649	336,385	505,035

14. RESIDENTIAL EXCHANGE BENEFITS UNDER THE TRADITIONAL RESIDENTIAL EXCHANGE PROGRAM

14.1 Reconstructed IOU REP Benefits for FY 2002-2008

The Lookback analysis seeks to first answer two questions: (1) what PF Exchange rates would have been established for the sale of exchange power to the IOUs; and (2) what ASCs would have been established for the purchase of exchange power from each IOU. Given the answers to those two questions, a more basic question can then be answered; namely, what REP benefits would the IOUs have received in the absence of the REP settlement agreements. These REP benefits are referred to as the "reconstructed" REP benefits for FY 2002-2008.

14.2 Reconstructed IOU REP Benefits for FY 2002-2006

BPA assumed, in the absence of the REP Settlement Agreements, that all of the IOUs, with the exception of Idaho Power, would have signed RPSAs in 2000. In that case, BPA would have calculated REP benefits based on the PF Exchange rate, appropriate ASC, and appropriate exchange loads for each IOU. Chapter 5 of this Study describes how BPA reconstructed the FY 2002-2006 "base" PF Exchange rate and associated CRACs for the sale of exchange power. Chapter 7 of this Study describes how BPA constructed the backcast ASCs for the purchase of exchange power. This Chapter 14 describes the analysis to determine the amount of REP benefits each IOU would have received during the Lookback period in the absence of the REP settlements.

BPA's assumption about Idaho Power is predicated on the outcome of the analysis of its reconstructed REP benefits for FY 2002-2006. Had Idaho Power signed an RPSA, it would have received $8.2 million in reconstructed REP benefits for FY 2002 that would have been applied to its existing deemer balance. However, Idaho Power would have then continued to accrue additional deemer balance obligations equaling $238.89 million for FY 2002-2006. As a result, it seemed reasonable to assume that Idaho Power would not have signed an RPSA in 2000. Chapter 15 addresses the treatment of deemer balances in the Lookback analysis.

In order to accurately calculate the reconstructed REP benefits, BPA must establish not only the appropriate "base" PF Exchange rate, but whether or not any CRAC or DDC would have been necessary. Therefore, BPA compared BPA's actual revenues collected to its actual costs in each fiscal year. Because BPA's actual revenues collected during FY 2002-2006 were sufficient to meet its costs for these same fiscal years, the actual amount of revenues collected in FY 2002-2006 is the starting point of this analysis. The actual revenues collected for the rate period are then adjusted by: (1) subtracting the amount of REP Settlement Agreement Benefits paid as expressed in Chapter 13; (2) subtracting the net cost to BPA of furnishing power to IOUs, included in Chapter 13; and (3) adding the net REP benefits determined by using the recalculated base PF Exchange rate and the backcast utility ASCs and eligible exchangeable loads, as summarized below. These annual adjusted revenue amounts for each fiscal year are the "Annual Revenue Targets."

If the model projects that revenues from recalculated rates fall short of the Annual Revenue Targets for a year, then the base PF Preference and base PF Exchange rates are increased by means of a CRAC percentage that is applied to both rates. The CRAC increases the revenue and, in turn, decreases the level of net REP benefits until the difference between the net revenues collected and the Annual Revenue Target is zero. The inverse is true if revenues over-collect the Annual Revenue Target. The level of Lookback REP benefits at a CRACed PF Exchange rate is solved in the model through an intrinsic goal-seeking function. Section 5.5 of this Study describes this process more completely, as well as Brodie, *et al.*, WP-07-E-BPA-58. Table 14.1, which is based on Post-Processor output, summarizes the forecast of Lookback benefits for FY 2002-2006. *See* FY 2002-2008 Lookback Documentation, WP-07-FS-8A, Table 5.3.6.

Table 14.1
Reconstructed REP Benefits – FY 2002-2006
($000)

	2002	2003	2004	2005	2006	Total
Avista	3,290	187	18,062	4,617	6,472	32,627
Idaho Power 1/	0	0	0	0	0	0
NorthWestern Energy	3,031	3,110	8,539	5,433	12,403	31,517
PacifiCorp	0	0	4,636	9,372	0	14,008
Portland General Electric	68,529	20,130	28,376	45,822	56,672	219,528
Puget Sound Energy	50,458	10,010	65,057	103,902	147,591	377,019
Total	125,308	32,437	124,671	169,145	223,138	674,699

1/ Assumes that Idaho Power did not sign an RPSA

14.3 Reconstructed IOU REP Benefits for FY 2007-2008

Chapter 9 of this Study describes how BPA reconstructed the FY 2007-2008 PF Exchange rate for the sale of exchange power. Chapter 11 of this Study describes how BPA constructed the backcast ASCs for the purchase of exchange power. Once these two pieces are reconstructed, the analysis to determine the amount of REP benefits each IOU would have received during the Lookback period can be completed.

Table 14.2 summarizes the reconstructed REP benefits for FY 2007-2008. *See* also FY 2002-2008 Lookback Documentation, WP-07-FS-8A, Tables 9.2.7 through 9.2.8.

Table 14.2
Reconstructed REP Benefits – FY 2007-2008
($000)

	2007	2008	Total
Avista	18,576	33,516	52,092
Idaho Power 1/	0	0	0
NorthWestern Energy	12,281	14,099	26,380
PacifiCorp	0	6,937	6,937
Portland General Electric	35,219	82,029	117,249
Puget Sound Energy	106,438	164,474	270,913
Total	172,514	301,055	473,569

1/ Assumes that Idaho Power did not sign an RPSA.

15. LOOKBACK AMOUNTS, RECOVERY AND RETURN

15.1 Introduction

The purpose of this chapter of the FY 2002-2008 Lookback Study is to explain how BPA arrives at the annual and total Lookback Amounts for each IOU and how it plans to recover these amounts from the IOUs and return them to the COUs. It also describes how BPA will establish and return amounts that the COUs overpaid in rates for FY 2007-2008 that are not otherwise included in Lookback Amounts. Last, this chapter addresses the derivation of the Definitive Benefit Amounts and Definitive Payment Amount and associated COU customer percentages that are needed for administration of the Interim Agreements.

The calculation of Lookback Amounts requires BPA to quantify the total payments to each IOU under the REP settlements, estimate the total amounts each IOU would have received under the REP in the absence of the REP settlement agreements (called the "reconstructed" REP benefits), and to then calculate the appropriate differences, or annual Lookback Amounts.

Several factors affect the calculations of the Lookback Amounts. These factors include but are not limited to the following:

(1) 2004 Amendments (to the REP Settlement Agreements) remanded to BPA;

(2) Reduction of Risk Discount remanded to BPA;

(3) Load Reduction Agreements (LRAs); and

(4) Deemer account balances that BPA asserts certain utilities owe BPA;

BPA's proposed treatment of these and other issues is described in this chapter.

15.2 Determining the IOU Annual Lookback Amounts For FY 2002-2008

To determine each IOU's annual and cumulative Lookback Amounts, BPA created an Excel spreadsheet model that takes certain inputs, most notably the REP settlement benefits (determined as described in Chapter 13), the reconstructed REP benefits (determined as described in Chapter 14), and deemer account balances (for Avista and Northwestern, including accrued interest) as of the beginning of FY 2002. Idaho Power's deemer balance does not factor into this analysis because, as described in Section 14.2, BPA assumed that Idaho Power would not have signed an RPSA in 2000. Therefore, its total Lookback Amount is equal to its REP settlement benefits received, as adjusted to FY 2009 dollars. In addition, the model uses certain assumptions regarding inflation and interest rates applicable to FY 2002-2008 and beyond. *See* Table 15.1 for a list of model inputs. This model is hereinafter referred to as the Lookback/ Lookforward Model (LBLF Model). This model is the source of tables included in this chapter, unless otherwise noted.

Table 15.1
Inputs for LBLF Model

1. Inputs to Model
    a. REP Settlement benefits and Load Reduction Agreement (LRA) payments made to IOUs from FY 2002 through the first six months of FY 2007 (referred to as 2007A);
    b. Settlement Payments that would have been made to IOUs for the last six months of FY 2007 (2007B) and for FY 2008;
    c. Reconstructed REP Benefits for FY 2002-2008;
    d. The allocation of FY 2008 reconstructed REP benefits after deemer adjustments into amounts applied toward paying down Lookback Amounts and amounts to be provided to IOUs (Definitive Benefit Amounts);
    e. FY 2009 REP benefits for each IOU before consideration of any deemer obligations or reductions for repayment of Lookback Amounts;
    f. FY 2002-2007 historical annual inflation rates, with an estimate for FY 2008, used to adjust Nominal Lookback amounts to FY 2009 dollars;
    g. Deemer account balances for Avista, Idaho Power, and NorthWestern, including accrued interest, as of October 1, 2001 (beginning FY 2002). PacifiCorp, Puget, and PGE had no deemer accounts;
    h. Annual average interest rates used to accrue simple interest on outstanding IOU deemer account balances starting in FY 2002;

i. 1-year through 20-year average annual T-Bill rates. This input is used to accrue interest on unpaid Lookback balances starting in FY 2009.

Given the model inputs listed in Table 15.1, and the treatment of certain issues described below, the LBLF model determines Lookback Amounts. In addition, it solves for the amount of FY 2009 REP benefits that will be applied against Lookback Amounts given policy decisions and assumptions also described.

15.2.1 Treatment of Deemer Balances

15.2.1.1 Overview

BPA's 1981 RPSAs established what was called a "deemer account." In the event that an exchanging utility's ASC fell below the applicable PF Exchange rate, rather than pay BPA, the utility would accumulate a balance in a deemer account based on the difference between its ASC and the PF Exchange rate multiplied by the utility's eligible exchange load. The 1981 RPSA provided that any obligations incurred under that RPSA would continue until satisfied, even if the RPSA expired. The RPSA also provided that the utility must repay its deemer balance before receiving any positive REP benefits. Avista, Idaho Power, and NorthWestern had positive deemer balances as of October 1, 2001, according to BPA's records.

BPA's determination of the amount of reconstructed REP benefits accounts for a utility's deemer balance. Specifically, any reconstructed REP benefits for FY 2002-2008 that are due to an IOU with a deemer balance are first applied to its deemer balance, until exhausted, before being compared to the REP settlement benefits to establish that IOU's annual Lookback Amount. Using this approach, NorthWestern extinguishes its deemer balance in FY 2006 and Avista in FY 2009. Since it is assumed that Idaho Power would not have signed an RPSA in 2000, as explained in Section 15.2.1.3.3., Idaho Power's deemer balance is not a factor in the calculation of its Lookback Amount.

15.2.1.2 Calculation of Deemer Balances

Deemer balances are calculated based on the terms and conditions of the 1981 RPSAs, the Suspension Agreement signed by Avista in 1987, a settlement agreement signed by NorthWestern in 1989, and the terms of the 2000 RPSA prototype contract.

Avista's Suspension Agreement stated that interest on its deemer balance would not compound; therefore, interest is calculated only on the deemer balance and not on the interest that has accrued, as provided for in the 2000 RPSA prototype contract. NorthWestern's (formerly Montana Power Company) settlement agreement specified that interest would compound, so the determination of interest on NorthWestern's deemer balance for Lookback purposes is calculated accordingly through FY 2001. When the agreement specifies compounding of interest, no distinction is needed between the deemer principal amount and the interest component.

The agreements for these utilities specified the same rate of interest on deemer accounts for both companies. The interest rate is the Federal Reserve Board, H.15 Selected Interest Rates, bank prime loan rate. Interest rates are fixed for each quarter beginning October, January, April, and July. The rates are determined by averaging the prime rates (to hundredths of a percent) for the second, third, and fourth months prior to each quarter. For example, the interest rate for the quarter beginning October 2007 would be set equal to the average of the prime rates for August, July, and June 2007.

15.2.1.3 Individual Utility Deemer Results

15.2.1.3.1 Avista Deemer Treatment

Table 15.2 shows how Avista's deemer balance, with accrued interest, is reduced each year by the reconstructed REP benefits. The first line of Table 15.2 shows Avista's start-of-year deemer balances. The second line shows pre-deemer reconstructed REP benefits. These reconstructed REP benefits are applied to the outstanding deemer balance until the deemer balance is reduced to zero. Avista's deemer balance was not completely amortized within the FY 2002–2008 time frame of this analysis. At the beginning of FY 2009, a $16.53 million deemer balance remains that is extinguished with the REP benefits due to Avista in FY 2009.

Because this Study uses a simple interest computation, the pre-deemer REP benefits are applied first to the deemer interest balance and then, if there are any remaining benefits due, to the principal balance. Interest is then computed on the new principal balance, excluding any previously accrued interest. Interest accruals use a mid-year convention. The result of the application of pre-deemer REP benefits and accrued interest is the end-of-year deemer balance. Additional documentation is provided in Table 15.1, Avista Deemer Calculations, FY 2002-2008 Lookback Study Documentation, WP-07-FS-BPA-08A.

Table 15.2
Avista Deemer Treatment
$ millions

	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007A	FY 2007B	FY 2008
SOY Deemer Balance	$85.583	$84.453	$86.023	$69.541	$66.895	$63.181	$55.507	$47.833
Reconstructed REP Benefits	$ 3.290	$ 0.187	$18.062	$ 4.617	$ 6.472	$ 9.288	$ 9.288	$33.516
Applied to Deemer	$ 3.290	$ 0.187	$18.062	$ 4.617	$ 6.472	$ 9.288	$ 9.288	$33.516
Interest Accrued	$ 2.160	$ 1.757	$ 1.580	$ 1.971	$ 2.758	$ 1.614	$ 1.614	$ 2.213
EOY Deemer Balance	$84.453	$86.023	$69.541	$66.895	$63.181	$55.507	$47.833	$16.531
Recst. REP Benefits Earned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Interest Rate Applied	5.49%	4.47%	4.02%	5.01%	7.01%	8.21%	8.21%	8.25%

15.2.1.3.2 NorthWestern Deemer Treatment

Table 15.3 shows how Northwestern's deemer balance, with accrued interest, is reduced each year by reconstructed REP benefits. The first line of the table shows NorthWestern's start-of-year deemer balance. The second line shows the pre-deemer reconstructed REP benefits. This amount is applied to the outstanding deemer balance until the deemer balance is reduced to zero. Additional documentation is provided in Table 15.2, NorthWestern Deemer Calculations, FY 2002-2008 Lookback Study Documentation, WP-07-FS-BPA-08A.

Table 15.3
Northwestern Deemer Treatment
$ millions

	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007A	FY 2007B	FY 2008
SOY Deemer Balance	$19.518	$16.980	$15.271	$ 7.047	$ 1.823	$ -	$ -	$ -
Reconstructed REP Benefits	$ 3.031	$ 2.110	$ 8.539	$ 5.433	$12.403	$ 6.140	$ 6.140	$14.099
Applied to Deemer	$ 3.031	$ 2.110	$ 8.539	$ 5.433	$ 1.823	$ -	$ -	$ -
Interest Accrued	$ 0.493	$ 0.401	$ 0.315	$ 0.209	$ -	$ -	$ -	$ -
EOY Deemer Balance	$16.980	$15.271	$ 7.047	$ 1.823	$ -	$ -	$ -	$ -
Recst. REP Benefits Earned	$ -	$ -	$ -	$ -	$10.581	$ 6.140	$ 6.140	$14.099
Interest Rate Applied	5.49%	4.47%	4.02%	5.01%	7.01%	8.21%	8.21%	8.25%

15.2.1.3.3 Idaho Power Deemer Treatment

Results described in Chapter 14 show Idaho Power would not have qualified for reconstructed REP benefits during FY 2003-2008 due to its low ASC. If BPA had assumed that Idaho Power would have signed an RPSA 2000, it would have qualified for about $8.2 million in reconstructed REP benefits in FY 2002. Idaho Power did not qualify for reconstructed REP benefits in FY 2003-2006, and if it had signed an RPSA in FY 2000, it would have accumulated more than $200 million of additional deemer balance (before interest accrual) for FY 2002-2006. Therefore, as described in Chapter 14, BPA assumed that Idaho Power would not have signed an RPSA in 2000 and would have no reconstructed REP benefits. As a result, Idaho Power's Lookback Amount is equal to the REP settlement benefits it received in FY 2002-2007. In addition, its Lookback Amount is the same regardless of whether it is assumed to have a deemer balance as of October 1, 2001, or not.

15.2.2 FY 2002-2007 Cumulative Lookback Amount Cannot Be Less than Zero

For purposes of calculating the FY 2002-2007 cumulative Lookback Amount for each utility, an IOU cannot have a negative cumulative Lookback Amount. This condition impacts only NorthWestern. For NorthWestern, the amount of FY 2007 reconstructed REP benefits that it keeps is set equal to $5.69 million because this amount results in a zero FY 2002-2007 Lookback Amount for NorthWestern.

15.2.3 Treatment of the Load Reduction Agreements (LRAs)

The LRAs with PacifiCorp and Puget were contracts wherein BPA bought back power from the two IOUs during FY 2002-2006 to limit BPA's exposure to the high and volatile market prices of the West Coast energy crisis. Marks, *et al.*, WP-07-E-BPA-62, at 62. Challenges to these agreements were dismissed by the Ninth Circuit as untimely and moot. BPA's calculation of Lookback Amounts treats the LRAs as enforceable agreements. Bliven, *et al.*, WP-07-E-BPA-52, at 19-20. Therefore, the LRA payments are included as part of the total calculation of REP settlement benefits paid to PacifiCorp and Puget. However, PacifiCorp and Puget are allowed to retain the greater of the REP benefits the utilities would have received or their LRA payments. By taking this approach, BPA's proposal effectively treats the LRA payments to PacifiCorp and Puget as "protected" payments that are not subject to recovery through the Lookback.

15.2.4 Treatment of the Reduction of Risk Discount

In *Snohomish*, the Court determined that the Reduction of Risk Discount was actually a part of the REP Settlement Agreements. *See* Bliven, *et al.*, WP-07-E-BPA-52, at 20. In the Lookback analysis, the Reduction of Risk Discount payments are treated in the same manner as any other non-LRA payment made under the REP Settlement Agreements. Payments made to PacifiCorp and Puget for the Reduction of Risk Discount are not "protected" and are therefore included in the calculation of the REP settlement benefits.

15.2.5 Results

The inputs and decisions stated above are applied on an annual basis to calculate the annual Lookback Amounts for each IOU for FY 2002-2007. In the Lookback analysis, the annual Lookback Amounts for FY 2002-2007 are escalated to 2009 dollars in order to adjust for the effects of inflation. Table 15.4 shows the resulting annual and cumulative Lookback Amounts for each IOU, in 2009 dollars, for FY 2002-2007. Table 15.9 provides details of the calculations of the Lookback Amounts in Table 15.4.

Table 15.4
Summary of Lookback Amounts
millions of 2009$

	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	Total FY 2002-2006	FY 2007	Total FY 2002-2007
Avista	$ 14.271	$ 10.623	$ 13.693	$ 13.167	$ 12.879	$ 64.632	$ 11.136	$ 75.768
Idaho	$ 17.607	$ 14.250	$ 18.323	$ 17.608	$ 17.230	$ 85.017	$ 16.725	$ 101.742
Northwestern **1/**	$ 3.753	$ 2.812	$ 3.637	$ 3.494	$ (8.008)	$ 5.687	$ (5.687)	$ -
Pacific	$ 45.744	$ 31.081	$ 43.659	$ 42.177	$ 40.884	$ 203.546	$ 48.707	$ 252.253
PGE	$ (48.553)	$ 31.599	$ 47.434	$ 48.263	$ 46.369	$ 125.111	$ 4.470	$ 129.581
Puget	$ 67.822	$ 33.630	$ 64.731	$ 62.532	$ 33.513	$ 262.227	$ (55.020)	$ 207.208
Total	**$ 100.643**	**$ 123.994**	**$ 191.476**	**$ 187.240**	**$ 142.867**	**$ 746.221**	**$ 20.331**	**$ 766.552**

1/ Northwestern's negative FY 07 Lookback Amount is set equal to FY02-06 Lookback so FY02-07 Lookback not less than 0.

15.3 Recovery of the FY 2002-2007 Lookback Amounts

BPA intends to recover the Lookback Amounts by reducing the amounts of REP benefits paid to the IOUs in the future, with these reductions applying to outstanding Lookback balances. The allocation of REP benefits between the amounts applied toward Lookback Amounts and the amounts paid to the IOUs will be determined in each rate period. Bliven, *et al.*, WP-07-E-BPA-52, at 23. Sections 15.3.1 and 15.3.2 describe these allocations of benefits for FY 2008 and FY 2009, respectively. Interest will accrue on the outstanding Lookback balances. Section 15.3.3 describes the accrual of interest on Lookback balances. Section 15.3.4 describes the time frame over which Lookback Amounts would be recovered from the IOUs based on the simple assumption that future REP benefits and other factors are the same as those for FY 2009.

15.3.1 Treatment of FY 2008 Reconstructed REP Benefits and Definitive Benefit Amounts

In March 2008, BPA offered Interim Agreements to the IOUs, with the exception of Idaho Power, that resulted in interim payments to Avista, NorthWestern, PGE, and Puget. These interim payments are subject to a true-up to the Definitive Benefit Amounts, for FY 2008, established in the 2007 Supplemental Wholesale Power Rate Case.

The Definitive Benefit Amount for each IOU is equal to the REP benefit payments for FY 2008 for each IOU as determined by the Administrator. Each utility's Definitive Benefit Amount is calculated in three steps. First, BPA determines the reconstructed REP benefits that the IOU would have received in FY 2008. Second, BPA subtracts from the reconstructed REP benefits any outstanding deemer balances that the IOU may have had with BPA. Third, BPA subtracts an additional amount from the remaining reconstructed REP benefits to apply toward the IOU's outstanding Lookback Amount. After making this final adjustment, the resulting amount is the reconstructed REP benefits payment for FY 2008. This amount is the Definitive Benefit Amount for each utility.

The amount of reconstructed FY 2008 REP benefits applied toward each IOU's outstanding Lookback Amount is based on a goal of providing a total amount of reconstructed REP benefits to the IOUs in FY 2008 that is close to the total amount of REP benefits to be paid to all IOUs in FY 2009. As described in Section 15.3.2, the total amount of REP benefits paid to all IOUs in FY 2009 is estimated to be $178.39 million. This amount is described as an estimated amount because the amount finally provided to the IOUs will be determined by the final ASCs that will be established in March 2009 and the actual eligible exchange loads during FY 2009. Given this FY 2009 amount, BPA set the total reconstructed FY 2008 REP benefits applied toward the IOUs' outstanding Lookback Amounts (total Definitive Benefit Amount) at $180 million.

Table 15.5 shows the derivation of the Definitive Benefit Amounts by utility. The FY 2008 reconstructed REP benefits before adjustments come from Table 14.2 above. The reconstructed benefits applied to deemer balances come from Tables 15.2 and 15.3. The amounts of FY 2008 reconstructed benefits, after deemer adjustment, that are applied to Lookback Amounts are determined as follows. Avista and Idaho Power have no reconstructed benefits, after deemer adjustment, so the amounts applied to their Lookback Amounts are zero. NorthWestern has no Lookback Amount, so none of its FY 2008 reconstructed REP benefits are applied. Because PacifiCorp did not sign an Interim Agreement, BPA applies all of its FY 2008 reconstructed REP benefits to its Lookback Amount. For PGE and Puget, the reconstructed REP benefits applied to their Lookback Amounts are the amounts that result in a total Definitive Benefit Amount of $180 million. PGE and Puget's reconstructed FY 2008 REP benefits are reduced by the same percentage to determine their respective amounts applied to Lookback Amounts.

Table 15.5
Summary of FY 2008 Reconstructed REP Benefits
millions of 2008$

	FY 08 Benefits Before Adjustments	FY 08 Benefits Applied to Deemer Balance	FY 08 Benefits After Deemer Adjustment	FY 08 Benefits Applied to Lookback	FY 08 Definitive Benefit Amounts
Avista	$ 33.516	$ 33.516	$ 0.000	$ 0.000	$ 0.000
Idaho	$ 0.000	$ 0.000	$ 0.000	$ 0.000	$ 0.000
Northwestern	$ 14.099	$ 0.000	$ 14.099	$ 0.000	$ 14.099
Pacific	$ 6.937	$ 0.000	$ 6.937	$ 6.937	$ 0.000
PGE	$ 82.029	$ 0.000	$ 82.029	$ 26.822	$ 55.207
Puget	$ 164.474	$ 0.000	$ 164.474	$ 53.780	$ 110.694
Total	**$ 301.055**	**$ 33.516**	**$ 267.539**	**$ 87.539**	**$ 180.000**

15.3.2 Treatment of REP Benefits for FY 2009 and Beyond

Since the IOUs have already passed payments received under the REP settlements on to their residential and small farm customers, BPA will recover Lookback Amounts from the IOUs by reducing future REP benefits they would otherwise receive. The amount of this reduction in

REP benefits will be determined by the Administrator in each rate proceeding, with a goal to complete the recovery and return of the Lookback Amounts within seven years. For FY 2009, BPA is setting an IOU's REP benefits paid at no less than 50 percent of its total FY 2009 REP benefits after deemer adjustment.

The LBLF model solves for the amounts of REP benefits that need to be applied to Lookback Amounts in order to amortize the Lookback Amounts over a given time period, given a set of inputs and assumptions. These inputs and assumptions are:

1. FY2002-2008 Lookback Amounts from Table 15.4,
2. FY 2008 benefits applied to Lookback Amounts from Table 15.5,
3. Assumed deemer balances as of September 30, 2008 that must be extinguished before REP benefits will be available to reduce Lookback Amounts or pay to the utility from Tables 15.2 and 15.3,
4. FY 2009 REP benefits before deemer adjustment from the FY 2009 Wholesale Power Rate Development Study Documentation, WP-07-FS-BPA-13A, Table 2.9, column K,
5. Interest charged on unamortized Lookback Amounts from Table 15.7,
6. The 7 year amortization goal,
7. The limitation that an IOU's REP benefits paid be no less than 50 percent of its total FY 2009 REP benefits after deemer adjustment, and
8. The assumptions for FY 2010 and beyond that 1) REP benefits remain the same as FY 2009 benefits (in nominal dollars); 2) the 50 percent floor on REP benefits paid continues and 3) the FY 2009 interest rates on unamortized Lookback amounts continue to be used.

The total amount of FY 2009 REP benefits applied to Lookback Amounts given these inputs and assumptions is $70.769 million. Table 15.6 summarizes FY 2009 results for each IOU.

Table 15.6
Summary of FY 2009 REP Benefits
$ millions

	Before Deemer Adjustment	After Deemer Adjustments	FY 09 Benefits applied to Lookback	REP Benefits After Lookback Adjustment	Percent of REP Benefits Retained	Remaining Lookback Amount at the End of FY 09 1/
Avista	$ 22.091	$ 5.560	$ 2.571	$ 2.989	54%	$ 76.517
Idaho	$ -	$ -	$ -	$ -	NA	$ 106.861
Northwestern	$ 6.888	$ 6.888	$ -	$ 6.888	100%	$ -
Pacific	$ 55.515	$ 55.515	$ 26.252	$ 29.264	53%	$ 229.680
PGE	$ 66.527	$ 66.527	$ 16.811	$ 49.716	75%	$ 89.917
Puget	$ 114.671	$ 114.671	$ 25.135	$ 89.536	78%	$ 134.220
Total	**$ 265.691**	**$ 249.161**	**$ 70.769**	**$ 178.392**	**72%**	**$ 637.195**

1/ Includes approximate FY 2009 Interest accruals totaling $28.95 million

15.3.3 Accrual of Interest on Lookback Balances

BPA will accrue interest on unamortized Lookback balances. The rate of interest will be determined each rate period. The interest rate applied for FY 2009 is the T-Bill rate for terms equal to the number of years that BPA expects it will take for each IOU to return its respective Lookback Amounts. For example, a 7-year amortization period assumes a 7-year T-Bill rate. The average daily T-Bill rates are computed for the period starting October 1, 2001. The terms are those corresponding to the projected years Lookback Amounts are amortized from Table 15.8 below. The rate corresponding to a 20-year term is used for Idaho Power. Table 15.7 shows the terms and interest rates.

Table 15.7
Interest Rates Applied to Unamortized Lookback Amounts
in FY 2009

	T-Bill Term	Interest Rate
Avista	10 year	4.64%
Idaho Power	20 year	5.03%
NorthWestern Energy	NA	NA
PacifiCorp	12 year	4.57%
Portland General Electric	7 year	4.21%
Puget Sound Energy	7 year	4.21%

15.3.4 Time Frame for Recovery of Lookback Amounts

Given the inputs and assumptions described in Section 15.3.2, Puget and PGE will amortize their respective Lookback Amounts in 2015 or within 7 years. Avista will amortize its Lookback Amount in 2018 and PacifiCorp in 2020. For all utilities except Avista, the REP benefits applied to Lookback Amounts and amounts paid (retained) in FY 2010 through the projected year that respective Lookback Amounts are fully amortized are equal to the FY 2009 amounts shown in Table 15.6. For Avista, the FY 2009 amounts applied to Lookback Amount and paid to Avista are smaller than the respective FY 2010 through FY 2018 amounts because the FY 2009 amounts reflect the extinguishing of Avista's remaining deemer balance. FY 2010 through FY 2018 amounts applied to Lookback and paid to Avista are $10.21 million and $11.88 million, respectively. See Table 15.3, Lookback Amortization, FY 2002-2008 Lookback Study Documentation, WP-07-FS-BPA-08A.

Idaho Power's forecast FY 2009 ASC is less than the FY 2009 PF Exchange rate so it would not qualify for REP benefits in FY 2009. *See* FY 2009 Wholesale Power Rate Development Study Documentation, WP-07-FS-BPA-13A, Table 2.9 Columns A and B. Therefore, BPA assumes it does not sign an RPSA that is effective for FY 2009.

Table 15.8
Projected Year Lookback Amounts Are Fully Amortized Assuming FY 2009 Benefit Levels Continue

Avista	2018
Idaho Power	not amortized
NorthWestern Energy	2008
PacifiCorp	2020
Portland General Electric	2015
Puget Sound Energy	2015

15.4 Return of Lookback Amounts to COUs

The Lookback Amounts are amounts that were overpaid to the IOUs during the FY 2002-2007 period due to the REP settlement agreements that will be recovered from the IOUs and returned to the COUs over time, beginning in FY 2009. As such, the Lookback Amounts by IOU are the respective IOUs' obligations to return overpayments they received due to the settlement agreements. This amount, however, is not identical to the overcharges to be returned to the COUs. The Lookback Amounts do not reflect amounts due to the IOUs and overcharges to the COUs for FY 2008 because no REP settlement benefits were disbursed to the IOUs in FY 2008. FY 2007 is complicated by the fact that REP settlement benefits for the period October 2006 through March 2007 (the 2007A period in Table 15.9) were disbursed to the IOUs, but settlement benefits for April 2007 through September 2007 (2007B in Table 15.9) were not disbursed even though they were collected in COU rates. Section 15.5 describes the derivation and return of FY 2007-2008 overcharges. This section describes the derivation and return of Lookback Amounts for FY 2009.

In addition to the factors noted above, BPA's decision to return Lookback Amounts as customer-specific credits rather than by reductions in future PF rates means that some additional adjustments must be made to correctly allocate returns of Lookback Amounts to the COUs in proportion to the amounts COUs were overcharged. Specifically, overcharges incurred in FY 2007, the FY 2007 Lookback Amount in 2009$, Table 15.4 above and also Table 15.9, column L, line 69, $20.331 million, will be returned as part of the return of FY 2007-2008 overcharges, not as Lookback Amounts to be returned to the COUs that paid the PF-02 rates.

FY 2008 reconstructed REP benefits applied to the Lookback and FY 2009 REP benefits applied to the Lookback represent amounts recovered from the IOUs that are due to the COUs that were overcharged under PF-02 rates. Finally, the Lookback Amounts were constructed from the settlement benefits paid to the IOUs. These amounts paid in FY 2003 and FY 2004 reflected the deferral of payment of a portion of the settlement agreement costs included in COU rates in FY 2003 and the subsequent payment of deferred amounts in subsequent years. See FY 2002-2008 Lookback Study Documentation, WP-07-FS-BPA-08A, Tables 13.1.2 through 13.1.7. There remains $16.50 million, including interest, of the FY 2003-2004 deferral that BPA collected in rates but did not disburse to the IOUs. BPA will include this $16.50 million in amounts returned to the COUs in FY 2009.

The total Lookback Amount that will be returned in FY 2009 to COUs that paid PF-02 rates is as follows: $70.769 million of FY 2009 REP benefits applied to Lookback (Table 15.6), plus $87.539 million of FY 2008 reconstructed REP benefits applied to Lookback (Table 15.5), minus $20.331 million adjustment for FY 2007 Lookback amounts due and returned to COUs that paid the PF-07 rates (Table 15.9, column L, line 69), plus $16.500 million of net FY 2003-2004 deferrals collected in rates but not disbursed to IOUs, for a total of $154.477 million.

BPA will return the $154.477 million in FY 2009 to eligible COUs as monthly credits on BPA power bills in essentially the same manner that it will return the FY 2007-2008 overcharges to COUs. First, the $154.48 million is apportioned 77.3722 percent to a non-Slice FY 2009 Lookback return amount and 22.6278 percent to a Slice FY 2009 Lookback return amount. This results in a non-Slice amount of $119.522 million and a Slice amount of $34.955 million. Individual customer payment amounts are calculated by applying customer-specific percentages to these non-Slice and Slice amounts. For each customer, its non-Slice percentage is equal to the ratio of BPA's FY 2002-2006 PF non-Slice revenues from each such customer to total non-Slice PF revenues, both of which would include Block purchases by Slice customers. BPA determined the non-Slice customer percentages based on the customers' shares of FY 2002-2006 PF-02 revenue, including PF HLH Energy, PF LLH Energy, PF Demand, PF Load Variance, LB, FB and SN CRACs, Irrigation Rate Mitigation Product, Conservation Incentive Credit, Conservation and Renewables Discount, and Low Density Discount. These shares are calculated from the respective final (or revised final, if applicable) amounts each COU was billed under the PF-02 rates. Table 15.4, Non-slice PF-02 Revenue and Revenue Shares, FY 2002-2008 Lookback Study Documentation, WP-07-FS-BPA-08A, shows annual non-Slice PF-02 revenues, total FY 2002-2006 non-Slice PF-02 revenues, and customer percentages of total BPA PF-02 non-Slice revenues, all by customer. The non-slice PF-02 Revenue Shares, in Table 15.4 of the Lookback Study Documentation, are the non-slice PF-02 Revenue Shares in Table 15.10 below.

For each Slice customer, its percentage of the Slice FY 2009 Lookback return amount is equal to the ratio of its Slice percentage divided by the total Slice percentage (22.6278 percent). Table 15.10, FY 2009 Lookback Credit Amounts, shows the derivation of individual customer FY 2009 bill credit amounts. Annual amounts will be credited in 12 equal monthly installments, unless BPA agrees to an alternative distribution on a customer-specific basis.

15.5 Return of FY 2007-2008 Overcharges to COUs

For FY 2007-2008, all REP settlement costs were included in the Priority Firm (PF) rate paid by preference customers. However, BPA suspended settlement payments to the IOUs in May 2007, and will have accumulated approximately $505 million in unpaid REP settlement costs as cash in its reserves by the end of October 2008 (when preference customers will have paid their September 2008 power bills). Since this cash will be in the BPA Fund, return of FY 2007-2008 overcharges to COUs does not need to be contingent on reductions in future REP benefits paid to IOUs, as is the case for the Lookback Amounts. Therefore, BPA will return the FY 2007-2008 overcharges to COUs that paid the PF-07 rates by making payments to the COUs in early FY 2009. As described below, a majority of COUs received a partial return of the FY 2007-2008 overcharges in April 2008.

For FY 2007, $337.027 million in REP settlement costs were included in the PF Preference rate. *See* Tables 13.2, 13.2, and 15.9, column L lines 60 and 61 in this Study. The Lookback analysis calculates that the total reconstructed IOU REP benefits that IOUs keep (after adjusting for deemer amounts and for the limitation that NorthWestern's FY 2002-2007 Lookback Amount cannot be less than zero) for FY 2007 is $149.058 million (*see* Table 15.9, column L line 69). The difference between these amounts, $187.969 million, is the FY 2007 overcharges to be returned to COUs.

For FY 2008, $336.385 million in REP settlement costs were included in the PF Preference rate. Reconstructed REP benefits after adjusting for deemer amounts for FY 2008 is $267.539. *See* Table 15.5, also Table 15.9, column K, line 69. The difference between these amounts, $68.846 million, is the FY 2008 overcharges to be returned to COUs. The total amount of overcharges to be returned to COUs for FY 2007-2008 (Definitive Payment Amount) is therefore $256.815 million.

BPA will return the Definitive Payment Amount by making lump sum payments to the eligible COUs based on customer-specific percentages that reflect customers' contributions to the overcharges, provided that BPA may agree to an alternative method of returning the amount on a customer-specific basis. First, the Definitive Payment Amount is apportioned 77.3722 percent to a non-Slice Definitive Payment Amount and 22.6278 percent to a Slice Definitive Payment Amount. This results in a non-Slice Definitive Payment Amount of $198.703 million and a Slice Definitive Payment Amount of $58.112 million.

Individual customer payment amounts are calculated by applying customer-specific percentages to the Non-Slice Definitive Payment Amount and the Slice Definitive Payment Amount. For each customer, its non-Slice percentage is equal to the ratio of BPA's FY 2007 PF non-Slice revenues from each such customer to total non-Slice PF revenues, both of which would include Block purchases by Slice customers. BPA determined the non-Slice customer percentages based on the customers' shares of FY 2007 Priority Firm (PF-07) revenue, including PF HLH Energy, PF LLH Energy, PF Demand, PF Load Variance, Irrigation Rate Mitigation Product, Conservation Incentive Credit, Conservation Rate Credit, and Low Density Discount. These shares are calculated from the respective final (or revised final, if applicable) amounts each COU was billed for FY 2007 under the PF-07 rates. For each Slice customer, its percentage of the Slice Definitive Payment Amount is equal to the ratio of its Slice percentage divided by the total Slice percentage (22.6278 percent).

In late February 2008, BPA offered 127 qualifying COUs Standstill and Interim Relief Payment Agreements (Interim Agreements) that provided "interim" payments to COUs to return an estimated portion of the overcharges due to the REP Settlement Agreements collected in the PF-07 power rates. These interim payments are subject to true-up to the final determinations made in the Administrator's Final Record of Decision for the 2007 Supplemental Wholesale Power Rate Case, which constitutes the Definitive Payment ROD for purposes of the Interim Agreements. One hundred COUs executed Interim Agreements. BPA disbursed interim payments to the parties that executed Interim Agreements on April 2, 2008.

For COUs that signed Interim Agreements, customer payment amounts will be used to determine true-up payments according to the terms and conditions of those agreements. For COUs that did not execute Interim Agreements, customer payment amounts, plus interest as specified below, will be provided in lump sum payments by electronic funds transfer (EFT) as promptly as practicable after the issuance of the Administrator's Supplemental Final Record of Decision for the 2007 Supplemental Wholesale Power Rate Case.

In order to put COUs that did not execute Interim Agreements on a comparable financial basis with COUs that executed agreements, interest will be added to the customer payment amounts for COUs that did not sign Interim Agreements. Interest is calculated on the amount of the interim payment that the COU would have received had it executed an Interim Agreement. Interest will be simple interest and will accrue from April 2, 2008 (the date interim payments were made to customers that executed Interim Agreements) through September 30, 2008.

The interest rate applicable to the interim payment amounts is 1.56 percent based on the six-month annual rate of interest posted under the title "Daily Treasury Yield Curve Rates" as published on the U.S. Department of Treasury Web site for April 2, 2008. This interest rate is available at the following Web site: www.treasury.gov/offices/domestic-finance/debt-management/interest-rate/yield.shtml. Table 15.11, FY 2007-2008 Customer Payment Amounts, provides customer non-Slice and Slice percentages, customer payment amounts, interim payments, Interim Agreement true-up payments and interest amounts.

Table 15.9
Lookback Amount Computation Detail by Company by Year

A	B	C	D	E	F	G	H	I	J	K	L	M
			2002	2003	2004	2005	2006	2007A	2007B	2008	**Total 2007**	**Total 2002 to 2007B**
1	**Avista**											
2		Settlement Benefits	$ 11.807	$ 8.976	$ 11.903	$ 11.816	$ 11.922	$ 10.582	$ -	$ -	$ 10.582	$ 67.005
3		Settlement Benefits Co. *would have received*							$ 10.561	$ 21.005	$ 10.561	$ 10.561
4		Reconstructed REP Benefits before Deemer Adjust	$ 3.290	$ 0.187	$ 18.062	$ 4.617	$ 6.472	$ 9.288	$ 9.288	$ 33.516	$ 18.576	$ 51.204
5		Reconstructed REP Benefits Applied to Deemer	$ 3.290	$ 0.187	$ 18.062	$ 4.617	$ 6.472	$ 9.288	$ 9.288	$ 33.516	$ 18.576	$ 51.204
6		Reconstructed REP Benefits after Deemer Adjust	$ 0.000	$ (0.000)	$ 0.000	$ (0.000)	$ 0.000	$ 0.000	$ -	$ -	$ 0.000	$ 0.000
7		Amount Company Keeps **1/**	$ 0.000	$ (0.000)	$ 0.000	$ (0.000)	$ 0.000	$ 0.000	$ -	$ -	$ 0.000	$ 0.000
8		Nominal Lookback Amount **2/**	$ 11.807	$ 8.976	$ 11.903	$ 11.816	$ 11.922	$ 10.582	$ -	$ -	$ 10.582	$ 67.005
9		Lookback Amount in 2009$ 3/	$ 14.271	$ 10.623	$ 13.693	$ 13.167	$ 12.879	$ 11.136	$ -	$ -	$ 11.136	$ 75.768
10												
11	**Idaho**											
12		Settlement Benefits	$ 14.567	$ 12.041	$ 15.927	$ 15.800	$ 15.949	$ 15.893	$ -	$ -	$ 15.893	$ 90.178
13		Settlement Benefits Co. *would have received*							$ 15.866	$ 31.578	$ 15.866	$ 15.866
14		Reconstructed REP Benefits before Deemer Adjust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15		Reconstructed REP Benefits Applied to Deemer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16		Reconstructed REP Benefits after Deemer Adjust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17		Amount Company Keeps **1/**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Nominal Lookback Amount **2/**	$ 14.567	$ 12.041	$ 15.927	$ 15.800	$ 15.949	$ 15.893	$ -	$ -	$ 15.893	$ 90.178
19		Lookback Amount in 2009$ 3/	$ 17.607	$ 14.250	$ 18.323	$ 17.608	$ 17.230	$ 16.725	$ -	$ -	$ 16.725	$ 101.742
20												
21	**Northwestern**											
22		Settlement Benefits	$ 3.105	$ 2.376	$ 3.161	$ 3.135	$ 3.168	$ 1.995	$ -	$ -	$ 1.995	$ 16.941
23		Settlement Benefits Co. *would have received*							$ 1.990	$ 3.947	$ 1.990	$ 1.990
24		Reconstructed REP Benefits before Deemer Adjust	$ 3.031	$ 2.110	$ 8.539	$ 5.433	$ 12.403	$ 6.140	$ 6.140	$ 14.099	$ 12.281	$ 43.797
25		Reconstructed REP Benefits Applied to Deemer	$ 3.031	$ 2.110	$ 8.539	$ 5.433	$ 1.823	$ -	$ -	$ -	$ -	$ 20.936
26		Reconstructed REP Benefits after Deemer Adjust	$ 0.000	$ 0.000	$ -	$ -	$ 10.581	$ 6.140	$ 6.140	$ 14.099	$ 12.281	$ 22.862
27		Amount Company Keeps **1/**	$ 0.000	$ 0.000	$ -	$ -	$ 10.581	$ 6.140	$ 1.260	$ 14.099	$ 7.400	$ 17.981
28		Nominal Lookback Amount **2/**	$ 3.105	$ 2.376	$ 3.161	$ 3.135	$ (7.413)	$ (4.145)	$ (1.260)	$ (14.099)	$ (5.405)	$ (1.040)
29		Lookback Amount in 2009$ 3/	$ 3.753	$ 2.812	$ 3.637	$ 3.494	$ (8.008)	$ (4.362)	$ (1.326)	$ (14.463)	$ (5.688)	$ (0.000)
30												

Table 15.9
Lookback Amount Computation Detail by Company by Year

A	B	C	D 2002	E 2003	F 2004	G 2005	H 2006	I 2007A	J 2007B	K 2008	L **Total 2007**	M **Total 2002 to 2007B**
31	**Pacific**											$ 397.988
32		Settlement Benefits	$ 37.847	$ 26.263	$ 37.951	$ 37.847	$ 37.846	$ 46.285	$ -	$ -	$ 46.285	$ 224.040
33		Settlement Benefits Co. *would have received*							$ 46.285	$ 92.584	$ 46.285	$ 46.285
34		LRA Payments	$ 79.216	$ 83.139	$ 83.367	$ 83.139	$ 83.135	$ -	$ -	$ -	$ -	$ 411.996
35		Total Payments received (Line 32 + Line 34)	$ 117.064	$ 109.402	$ 121.318	$ 120.986	$ 120.981	$ 46.285	$ -	$ -	$ 46.285	$ 636.036
36		Reconstructed REP Benefits	$ -	$ -	$ 4.636	$ 9.372	$ -	$ -	$ -	$ 6.937	$ -	$ 14.008
37		Amount Company Keeps **4/**	$ 79.216	$ 83.139	$ 83.367	$ 83.139	$ 83.135	$ -	$ -	$ 6.937	$ -	$ 411.996
38		Nominal Lookback Amount **5/**	$ 37.847	$ 26.263	$ 37.951	$ 37.847	$ 37.846	$ 46.285	$ -	$ (6.937)	$ 46.285	$ 224.040
39		Lookback Amount in 2009$ 3/	$ 45.744	$ 31.081	$ 43.659	$ 42.177	$ 40.884	$ 48.707	$ -	$ (7.116)	$ 48.707	$ 252.253
40												
41	**PGE**											
42		Settlement Benefits	$ 28.358	$ 46.830	$ 69.608	$ 89.131	$ 99.594	$ 39.467	$ -	$ -	$ 39.467	$ 372.987
43		Settlement Benefits Co. *would have received*							$ 39.792	$ 78.946	$ 39.792	$ 39.792
44		Reconstructed REP Benefits	$ 68.529	$ 20.130	$ 28.376	$ 45.822	$ 56.672	$ 17.610	$ 17.610	$ 82.029	$ 35.219	$ 254.748
45		Amount Company Keeps **6/**	$ 68.529	$ 20.130	$ 28.376	$ 45.822	$ 56.672	$ 17.610	$ 17.610	$ 82.029	$ 35.219	$ 254.748
46		Nominal Lookback Amount **2/**	$ (40.171)	$ 26.700	$ 41.232	$ 43.309	$ 42.923	$ 21.857	$ (17.610)	$ (82.029)	$ 4.247	$ 118.240
47		Lookback Amount in 2009$ **3/**	$ (48.553)	$ 31.599	$ 47.434	$ 48.263	$ 46.369	$ 23.001	$ (18.531)	$ (84.148)	$ 4.470	$ 129.581
48												
49	**Puget**											$ 255.073
50		Settlement Benefits	$ 56.114	$ 28.416	$ 56.267	$ 56.114	$ 56.114	$ 54.155	$ -	$ -	$ 54.155	$ 307.180
51		Settlement Benefits Co. would have received							$ 54.155	$ 108.324	$ 54.155	$ 54.155
52		LRA Payments	$ 116.666	$ 122.500	$ 122.835	$ 122.500	$ 122.500	$ -	$ -	$ -	$ -	$ 607.001
53		Total Payments (Line 50 + Line 52)	$ 172.779	$ 150.916	$ 179.103	$ 178.614	$ 178.614	$ 54.155	$ -	$ -	$ 54.155	$ 914.181
54		Reconstructed REP Benefits	$ 50.458	$ 10.010	$ 65.057	$ 103.902	$ 147.591	$ 53.219	$ 53.219	$ 164.474	$ 106.438	$ 483.457
55		Amount Company Keeps **4/**	$ 116.666	$ 122.500	$ 122.835	$ 122.500	$ 147.591	$ 53.219	$ 53.219	$ 164.474	$ 106.438	$ 738.531
56		Nominal Lookback Amount **5/**	$ 56.114	$ 28.416	$ 56.267	$ 56.114	$ 31.022	$ 0.936	$ (53.219)	$ (164.474)	$ (52.284)	$ 175.650
57		Lookback Amount in 2009$ 3/	$ 67.822	$ 33.630	$ 64.731	$ 62.532	$ 33.513	$ 0.985	$ (56.004)	$ (168.723)	$ (55.020)	$ 207.208
58												

Table 15.9
Lookback Amount Computation Detail by Company by Year

A	B	C	D 2002	E 2003	F 2004	G 2005	H 2006	I 2007A	J 2007B	K 2008	L Total 2007	M Total 2002 to 2007B
59	**Total**											
60		Settlement Benefits	$ 151.798	$ 124.903	$ 194.817	$ 213.843	$ 224.593	$ 168.377	$ -	$ -	$ 168.377	$ 1,078.332
61		Settlement Benefits Co. *would have received*							$ 168.649	$ 336.385	$ 168.649	$ 168.649
62		LRA Payments	$ 195.882	$ 205.639	$ 206.202	$ 205.639	$ 205.635	$ -	$ -	$ -	$ -	$ 1,018.996
63		Sub Total Settlement + LRA Payments	$ 347.680	$ 330.541	$ 401.019	$ 419.481	$ 430.228	$ 168.377	$ -	$ -	$ 168.377	$ 2,097.328
64		Reconstructed REP Benefits before Deemer Adjust	$ 125.308	$ 32.437	$ 124.671	$ 169.145	$ 223.138	$ 86.257	$ 86.257	$ 301.055	$ 172.515	$ 847.214
65		Reconstructed REP Benefits Applied to Deemer Account	$ 6.321	$ 2.296	$ 26.602	$ 10.050	$ 8.294	$ 9.288	$ 9.288	$ 33.516	$ 18.576	$ 72.139
66		Reconstructed REP Benefits after Deemer Adjust	$ 118.987	$ 30.140	$ 98.070	$ 159.095	$ 214.844	$ 76.969	$ 76.969	$ 267.539	$ 153.938	$ 775.074
67		Amount Company Keeps	$ 264.411	$ 225.768	$ 234.578	$ 251.460	$ 297.979	$ 76.969	$ 72.089	$ 267.539	$ 149.058	$ 1,423.255
68		Nominal Lookback Amount	$ 83.269	$ 104.773	$ 166.441	$ 168.021	$ 132.249	$ 91.408	$ (72.089)	$ (267.539)	$ 19.319	$ 674.073
69		Lookback Amount in 2009$	$ 100.643	$ 123.994	$ 191.476	$ 187.240	$ 142.867	$ 96.192	$ (75.861)	$ (274.450)	$ 20.330	$ 766.551

Notes: Summary of the formulas used for various lines of the model:

1/ For 2002 - 2008, Amount Company Keeps = Reconstructed REP Benefits after Deemer Adjust Except NWN 2007B amnt set = $1.26 so 02-07B LB = 0

2/ For 2002 - 2008 Nominal Lookback Amount=Settlement Benefits - Amount Company Keeps

3/

Escalation of Lookback Amount:	2002	2003	2004	2005	2006	2007	2008
Annual Inflation Rate Input		2.13%	2.87%	3.23%	3.16%	2.66%	2.58%
Escalation Factor	1.209	1.183	1.150	1.114	1.080	1.052	1.026

Lookback Amount in 2009 dollars = Nominal Lookback Amount (year) * Escalation Factor (year). Line 9, for example: $14.27 = $11.81 * 1.209

4/ For **2002 - 2007A**, Amount Company Keeps = Max(LRA Payments, REP Benefits))
For **2007B - 2008**, Amount Company Keeps = REP Benefits

5/ For **2002 - 2008** Nominal Lookback Amount = Total Payments received - Amount Company Keeps

6/ For **2002 - 2008**, Amount Company Keeps = REP Benefits

Table 15.10
FY 2009 Lookback Credit Amounts

Annual FY09 Lookback Credit Amount =	**$ 154,477,000**	$ 154,477,116
Slice FY09 Lookback Credit Amount	$ 34,954,747	$ 34,954,740
Non-Slice FY09 Lookback Credit Amount	$ 119,522,253	$ 119,522,376

	Name	Non-Slice PF02 Revenue Share	Non-Slice Annual FY09 Credit Amount	Non-Slice Monthly FY09 Credit Amount	Slice Percent (Retained Slice for PNGC Members)	Slice % Share	Slice Annual FY09 Credit Amount	Slice Monthly FY09 Credit Amount	Total Annual FY09 Credit	Total Monthly FY09 Credit
10055	Albion, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10005	Alder Mutual	0.0107%	$ 12,837	$ 1,070	0.00000%	0.00000%	$ -	$ -	$ 12,837	$ 1,070
10057	Ashland, City of	0.5462%	$ 652,870	$ 54,406	0.00000%	0.00000%	$ -	$ -	$ 652,870	$ 54,406
10015	Asotin County PUD #1	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10059	Bandon, City of	0.1878%	$ 224,459	$ 18,705	0.00000%	0.00000%	$ -	$ -	$ 224,459	$ 18,705
10024	Benton County PUD #1	1.3514%	$ 1,615,218	$ 134,602	1.76410%	7.79616%	$ 2,725,129	$ 227,094	$ 4,340,347	$ 361,696
10025	Benton REA	1.2380%	$ 1,479,729	$ 123,311	0.00000%	0.00000%	$ -	$ -	$ 1,479,729	$ 123,311
10027	Big Bend Elec Coop	0.6159%	$ 736,117	$ 61,343	0.00000%	0.00000%	$ -	$ -	$ 736,117	$ 61,343
10028	Big Horn County Electric Coop.	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10029	Blachly Lane Elec Coop	0.0000%	$ -	$ -	0.06577%	0.29066%	$ 101,600	$ 8,467	$ 101,600	$ 8,467
10061	Blaine, City of	0.2046%	$ 244,540	$ 20,378	0.00000%	0.00000%	$ -	$ -	$ 244,540	$ 20,378
10062	Bonners Ferry, City of	0.1541%	$ 184,125	$ 15,344	0.00000%	0.00000%	$ -	$ -	$ 184,125	$ 15,344
10064	Burley, City of	0.3564%	$ 425,951	$ 35,496	0.00000%	0.00000%	$ -	$ -	$ 425,951	$ 35,496
10044	Canby, City of	0.4964%	$ 593,274	$ 49,440	0.00000%	0.00000%	$ -	$ -	$ 593,274	$ 49,440
10065	Cascade Locks, City of	0.0606%	$ 72,378	$ 6,032	0.00000%	0.00000%	$ -	$ -	$ 72,378	$ 6,032
10046	Central Electric Coop	0.0000%	$ -	$ -	0.22965%	1.01490%	$ 354,756	$ 29,563	$ 354,756	$ 29,563
10047	Central Lincoln PUD	1.6349%	$ 1,954,105	$ 162,842	0.00000%	0.00000%	$ -	$ -	$ 1,954,105	$ 162,842
10048	Central Montana Electric Power Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10066	Centralia, City of	0.5552%	$ 663,547	$ 55,296	0.00000%	0.00000%	$ -	$ -	$ 663,547	$ 55,296
10067	Cheney, City of	0.3672%	$ 438,901	$ 36,575	0.00000%	0.00000%	$ -	$ -	$ 438,901	$ 36,575
10068	Chewelah, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10101	Clallam County PUD #1	1.7593%	$ 2,102,802	$ 175,234	0.00000%	0.00000%	$ -	$ -	$ 2,102,802	$ 175,234
10103	Clark County PUD #1	8.0133%	$ 9,577,632	$ 798,136	0.00000%	0.00000%	$ -	$ -	$ 9,577,632	$ 798,136
10105	Clatskanie PUD	0.8255%	$ 986,651	$ 82,221	0.97550%	4.31107%	$ 1,506,923	$ 125,577	$ 2,493,574	$ 207,798
10106	Clearwater Power	0.0000%	$ -	$ -	0.08223%	0.36340%	$ 127,026	$ 10,586	$ 127,026	$ 10,586
10109	Columbia Basin Elec Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10111	Columbia Power Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10113	Columbia REA	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10112	Columbia River PUD	0.8976%	$ 1,072,784	$ 89,399	0.00000%	0.00000%	$ -	$ -	$ 1,072,784	$ 89,399
10116	Consolidated Irrigation District #19	0.0062%	$ 7,376	$ 615	0.00000%	0.00000%	$ -	$ -	$ 7,376	$ 615
10118	Consumers Power	0.0000%	$ -	$ -	0.14518%	0.64160%	$ 224,270	$ 18,689	$ 224,270	$ 18,689
10121	Coos Curry Elec Coop	0.0000%	$ -	$ -	0.13270%	0.58645%	$ 204,991	$ 17,083	$ 204,991	$ 17,083
10378	Coulee Dam, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10123	Cowlitz County PUD #1	11.5368%	$ 13,789,046	$ 1,149,087	0.00000%	0.00000%	$ -	$ -	$ 13,789,046	$ 1,149,087
10070	Declo, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -

Table 15.10
FY 2009 Lookback Credit Amounts

Annual FY09 Lookback Credit Amount =	**$ 154,477,000**	$ -
Slice FY09 Lookback Credit Amount	$ 34,954,747	$ -
Non-Slice FY09 Lookback Credit Amount	$ 119,522,253	$ -

	Name	**Non-Slice PF02 Revenue Share**	**Non-Slice Annual FY09 Credit Amount**	**Non-Slice Monthly FY09 Credit Amount**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice % Share**	**Slice Annual FY09 Credit Amount**	**Slice Monthly FY09 Credit Amount**	**Total Annual FY09 Credit**	**Total Monthly FY09 Credit**
10136	Douglas Electric Cooperative	0.0000%	$ -	$ -	0.06518%	0.28805%	$ 100,688	$ 8,391	$ 100,688	$ 8,391
10071	Drain, City of	0.0645%	$ 77,128	$ 6,427	0.00000%	0.00000%	$ -	$ -	$ 77,128	$ 6,427
10142	East End Mutual Electric	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10144	Eatonville, Town of	0.0785%	$ 93,863	$ 7,822	0.00000%	0.00000%	$ -	$ -	$ 93,863	$ 7,822
10072	Ellensburg, City of	0.5924%	$ 708,033	$ 59,003	0.00000%	0.00000%	$ -	$ -	$ 708,033	$ 59,003
10156	Elmhurst Mutual P & L	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10157	Emerald County PUD	1.2731%	$ 1,521,688	$ 126,807	0.00000%	0.00000%	$ -	$ -	$ 1,521,688	$ 126,807
10158	Energy Northwest	0.0690%	$ 82,498	$ 6,875	0.00000%	0.00000%	$ -	$ -	$ 82,498	$ 6,875
10170	Eugene Water & Electric Board	1.8894%	$ 2,258,250	$ 188,188	2.43280%	10.75138%	$ 3,758,116	$ 313,176	$ 6,016,366	$ 501,364
10172	Fairchild AFB	0.2045%	$ 244,412	$ 20,368	0.00000%	0.00000%	$ -	$ -	$ 244,412	$ 20,368
10173	Fall River Elec Coop	0.0000%	$ -	$ -	0.07342%	0.32447%	$ 113,417	$ 9,451	$ 113,417	$ 9,451
10174	Farmers Electric Company	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10177	Ferry County PUD #1	0.2293%	$ 274,052	$ 22,838	0.00000%	0.00000%	$ -	$ -	$ 274,052	$ 22,838
10179	Flathead Elec Coop	2.0560%	$ 2,457,364	$ 204,780	0.00000%	0.00000%	$ -	$ -	$ 2,457,364	$ 204,780
10074	Forest Grove, City of	0.5719%	$ 683,579	$ 56,965	0.00000%	0.00000%	$ -	$ -	$ 683,579	$ 56,965
10183	Franklin County PUD #1	0.5806%	$ 693,932	$ 57,828	0.78510%	3.46963%	$ 1,212,799	$ 101,067	$ 1,906,731	$ 158,895
10186	Glacier Elec Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10190	Grant County PUD #2	3.8794%	$ 4,636,782	$ 386,399	0.00000%	0.00000%	$ -	$ -	$ 4,636,782	$ 386,399
10191	Grays Harbor PUD #1	0.9797%	$ 1,170,958	$ 97,580	1.16810%	5.16223%	$ 1,804,446	$ 150,370	$ 2,975,404	$ 247,950
10197	Harney Elec Coop	0.3094%	$ 369,861	$ 30,822	0.00000%	0.00000%	$ -	$ -	$ 369,861	$ 30,822
10597	Hermiston, City of	0.3388%	$ 404,947	$ 33,746	0.00000%	0.00000%	$ -	$ -	$ 404,947	$ 33,746
10076	Heyburn, City of	0.1708%	$ 204,146	$ 17,012	0.00000%	0.00000%	$ -	$ -	$ 204,146	$ 17,012
10202	Hood River Elec Coop	0.3036%	$ 362,831	$ 30,236	0.00000%	0.00000%	$ -	$ -	$ 362,831	$ 30,236
10203	Idaho County L & P	0.1319%	$ 157,618	$ 13,135	0.00000%	0.00000%	$ -	$ -	$ 157,618	$ 13,135
10204	Idaho Falls Power	0.5748%	$ 687,039	$ 57,253	0.69310%	3.06305%	$ 1,070,680	$ 89,223	$ 1,757,719	$ 146,476
10209	Inland P & L	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10230	Kittitas County PUD #1	0.1625%	$ 194,215	$ 16,185	0.00000%	0.00000%	$ -	$ -	$ 194,215	$ 16,185
10231	Klickitat County PUD #1	0.7414%	$ 886,155	$ 73,846	0.00000%	0.00000%	$ -	$ -	$ 886,155	$ 73,846
10234	Kootenai Electric Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10235	Lakeview L & P (WA)	0.8854%	$ 1,058,274	$ 88,190	0.00000%	0.00000%	$ -	$ -	$ 1,058,274	$ 88,190
10236	Lane County Elec Coop	0.0000%	$ -	$ -	0.09464%	0.41825%	$ 146,197	$ 12,183	$ 146,197	$ 12,183
10237	Lewis County PUD #1	2.4361%	$ 2,911,658	$ 242,638	0.00000%	0.00000%	$ -	$ -	$ 2,911,658	$ 242,638

Table 15.10
FY 2009 Lookback Credit Amounts

Annual FY09 Lookback Credit Amount =	**$ 154,477,000**	$ -
Slice FY09 Lookback Credit Amount	$ 34,954,747	$ -
Non-Slice FY09 Lookback Credit Amount	$ 119,522,253	$ -

	Name	Non-Slice PF02 Revenue Share	Non-Slice Annual FY09 Credit Amount	Non-Slice Monthly FY09 Credit Amount	Slice Percent (Retained Slice for PNGC Members)	Slice % Share	Slice Annual FY09 Credit Amount	Slice Monthly FY09 Credit Amount	Total Annual FY09 Credit	Total Monthly FY09 Credit
10239	Lincoln Elec Coop (MT)	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10242	Lost River Elec Coop	0.0000%	$ -	$ -	0.02456%	0.10854%	$ 37,940	$ 3,162	$ 37,940	$ 3,162
10244	Lower Valley Energy	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10246	Mason County PUD #1	0.1761%	$ 210,448	$ 17,537	0.00000%	0.00000%	$ -	$ -	$ 210,448	$ 17,537
10247	Mason County PUD #3	1.8392%	$ 2,198,256	$ 183,188	0.00000%	0.00000%	$ -	$ -	$ 2,198,256	$ 183,188
10078	McCleary, City of	0.1203%	$ 143,740	$ 11,978	0.00000%	0.00000%	$ -	$ -	$ 143,740	$ 11,978
10079	McMinnville, City of	2.0081%	$ 2,400,142	$ 200,012	0.00000%	0.00000%	$ -	$ -	$ 2,400,142	$ 200,012
10256	Midstate Elec Coop	0.9710%	$ 1,160,539	$ 96,712	0.00000%	0.00000%	$ -	$ -	$ 1,160,539	$ 96,712
10081	Milton Freewater, City of	0.2601%	$ 310,920	$ 25,910	0.00000%	0.00000%	$ -	$ -	$ 310,920	$ 25,910
10080	Milton, City of	0.1816%	$ 216,994	$ 18,083	0.00000%	0.00000%	$ -	$ -	$ 216,994	$ 18,083
10082	Minidoka, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10258	Mission Valley	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10259	Missoula Elec Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10260	Modern Elec Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10083	Monmouth, City of	0.2015%	$ 240,801	$ 20,067	0.00000%	0.00000%	$ -	$ -	$ 240,801	$ 20,067
10273	Nespelem Valley Elec Coop	0.1196%	$ 142,909	$ 11,909	0.00000%	0.00000%	$ -	$ -	$ 142,909	$ 11,909
10278	Northern Lights	0.0000%	$ -	$ -	0.06418%	0.28363%	$ 99,143	$ 8,262	$ 99,143	$ 8,262
10279	Northern Wasco County PUD	0.5733%	$ 685,221	$ 57,102	0.00000%	0.00000%	$ -	$ -	$ 685,221	$ 57,102
10284	Ohop Mutual Light Company	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10285	Okanogan County Elec Coop	0.0000%	$ -	$ -	0.01822%	0.08052%	$ 28,146	$ 2,345	$ 28,146	$ 2,345
10286	Okanogan County PUD #1	0.3819%	$ 456,451	$ 38,038	0.49510%	2.18802%	$ 764,816	$ 63,735	$ 1,221,267	$ 101,773
10288	Orcas P & L	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10291	Oregon Trail Coop	1.8121%	$ 2,165,898	$ 180,492	0.00000%	0.00000%	$ -	$ -	$ 2,165,898	$ 180,492
10294	Pacific County PUD #2	0.8903%	$ 1,064,125	$ 88,677	0.00000%	0.00000%	$ -	$ -	$ 1,064,125	$ 88,677
10304	Parkland L & W	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10306	Pend Oreille County PUD #1	0.2442%	$ 291,885	$ 24,324	0.38190%	1.68775%	$ 589,948	$ 49,162	$ 881,833	$ 73,486
10307	Peninsula Light Company	1.6367%	$ 1,956,226	$ 163,019	0.00000%	0.00000%	$ -	$ -	$ 1,956,226	$ 163,019
10086	Plummer, City of	0.0955%	$ 114,166	$ 9,514	0.00000%	0.00000%	$ -	$ -	$ 114,166	$ 9,514
10298	PNGC	3.0958%	$ 3,700,223	$ 308,352	2.80000%	12.37416%	$ 4,325,356	$ 360,446	$ 8,025,579	$ 668,798
10087	Port Angeles, City of	1.7490%	$ 2,090,394	$ 174,200	0.00000%	0.00000%	$ -	$ -	$ 2,090,394	$ 174,200
10706	Port of Seattle	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10326	Puget Sound Naval Shipyard (Bremerton)	0.7338%	$ 877,072	$ 73,089	0.00000%	0.00000%	$ -	$ -	$ 877,072	$ 73,089
10331	Raft River Elec Coop	0.0000%	$ -	$ -	0.03948%	0.17448%	$ 60,988	$ 5,082	$ 60,988	$ 5,082
10333	Ravalli County Elec Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10089	Richland, City of	2.1095%	$ 2,521,321	$ 210,110	0.00000%	0.00000%	$ -	$ -	$ 2,521,321	$ 210,110

Table 15.10
FY 2009 Lookback Credit Amounts

Annual FY09 Lookback Credit Amount =	**$ 154,477,000**	$ -
Slice FY09 Lookback Credit Amount	$ 34,954,747	$ -
Non-Slice FY09 Lookback Credit Amount	$ 119,522,253	$ -

	Name	Non-Slice PF02 Revenue Share	Non-Slice Annual FY09 Credit Amount	Non-Slice Monthly FY09 Credit Amount	Slice Percent (Retained Slice for PNGC Members)	Slice % Share	Slice Annual FY09 Credit Amount	Slice Monthly FY09 Credit Amount	Total Annual FY09 Credit	Total Monthly FY09 Credit
10338	Riverside Elec Company	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10091	Rupert, City of	0.2466%	$ 294,731	$ 24,561	0.00000%	0.00000%	$ -	$ -	$ 294,731	$ 24,561
10342	Salem Elec Coop	1.1577%	$ 1,383,739	$ 115,312	0.00000%	0.00000%	$ -	$ -	$ 1,383,739	$ 115,312
10343	Salmon River Elec Coop	0.0000%	$ -	$ -	0.07848%	0.34683%	$ 121,234	$ 10,103	$ 121,234	$ 10,103
10349	Seattle City Light	3.4471%	$ 4,120,062	$ 343,339	4.66760%	20.62772%	$ 7,210,368	$ 600,864	$ 11,330,430	$ 944,203
10352	Skamania County PUD #1	0.3734%	$ 446,267	$ 37,189	0.00000%	0.00000%	$ -	$ -	$ 446,267	$ 37,189
10354	Snohomish County PUD #1	8.3965%	$ 10,035,698	$ 836,308	4.99290%	22.06534%	$ 7,712,882	$ 642,740	$ 17,748,580	$ 1,479,048
10094	Soda Springs, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
11342	Southern MT G&T	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10360	South Side Electric	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10363	Springfield Utility Board	1.6589%	$ 1,982,772	$ 165,231	0.00000%	0.00000%	$ -	$ -	$ 1,982,772	$ 165,231
10379	Steilacoom, Town of	0.1201%	$ 143,489	$ 11,957	0.00000%	0.00000%	$ -	$ -	$ 143,489	$ 11,957
10095	Sumas, City of	0.0793%	$ 94,749	$ 7,896	0.00000%	0.00000%	$ -	$ -	$ 94,749	$ 7,896
10369	Surprise Valley Elec Coop	0.2767%	$ 330,700	$ 27,558	0.00000%	0.00000%	$ -	$ -	$ 330,700	$ 27,558
10370	Tacoma Public Utilities	10.0716%	$ 12,037,858	$ 1,003,155	0.00000%	0.00000%	$ -	$ -	$ 12,037,858	$ 1,003,155
10371	Tanner Elec Coop	0.2008%	$ 240,010	$ 20,001	0.00000%	0.00000%	$ -	$ -	$ 240,010	$ 20,001
10376	Tillamook PUD #1	0.9720%	$ 1,161,766	$ 96,814	0.00000%	0.00000%	$ -	$ -	$ 1,161,766	$ 96,814
10097	Troy, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10406	U.S. DOE Albany	0.0112%	$ 13,341	$ 1,112	0.00000%	0.00000%	$ -	$ -	$ 13,341	$ 1,112
10408	U.S. Naval Station, Everett (Jim Creek)	0.0365%	$ 43,569	$ 3,631	0.00000%	0.00000%	$ -	$ -	$ 43,569	$ 3,631
10409	U.S. Naval Submarine Base, Bangor	0.5124%	$ 612,419	$ 51,035	0.00000%	0.00000%	$ -	$ -	$ 612,419	$ 51,035
10388	Umatilla Elec Coop	0.0000%	$ -	$ -	0.32749%	1.44729%	$ 505,897	$ 42,158	$ 505,897	$ 42,158
10482	Umpqua Indian Utility Cooperative	0.0530%	$ 63,406	$ 5,284	0.00000%	0.00000%	$ -	$ -	$ 63,406	$ 5,284
10391	United Electric Coop	0.4876%	$ 582,773	$ 48,564	0.00000%	0.00000%	$ -	$ -	$ 582,773	$ 48,564
10399	USBIA Wapato	0.0171%	$ 20,485	$ 1,707	0.00000%	0.00000%	$ -	$ -	$ 20,485	$ 1,707
10426	USDOE-Richland	0.6536%	$ 781,208	$ 65,101	0.00000%	0.00000%	$ -	$ -	$ 781,208	$ 65,101
10434	Vera Irrigation District	0.6442%	$ 769,929	$ 64,161	0.00000%	0.00000%	$ -	$ -	$ 769,929	$ 64,161
10436	Vigilante Elec Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10440	Wahkiakum County PUD #1	0.1099%	$ 131,337	$ 10,945	0.00000%	0.00000%	$ -	$ -	$ 131,337	$ 10,945
10442	Wasco Elec Coop	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
11680	Weiser, City of	0.0000%	$ -	$ -	0.00000%	0.00000%	$ -	$ -	$ -	$ -
10446	Wells Rural Electric Company	1.3147%	$ 1,571,326	$ 130,944	0.00000%	0.00000%	$ -	$ -	$ 1,571,326	$ 130,944
10448	West Oregon Elec Coop	0.0000%	$ -	$ -	0.03042%	0.13444%	$ 46,992	$ 3,916	$ 46,992	$ 3,916
10451	Whatcom County PUD #1	0.6089%	$ 727,768	$ 60,647	0.00000%	0.00000%	$ -	$ -	$ 727,768	$ 60,647
10502	Yakama Power	0.0096%	$ 11,490	$ 958	0.00000%	0.00000%	$ -	$ -	$ 11,490	$ 958
	Total	**100%**	**$ 119,522,248**	**$ 9,960,198**	**22.62780%**	**100%**	**$ 34,954,747**	**$ 2,912,895**	**$ 154,476,995**	**$ 12,873,093**

Table 15.11

FY 2007-2008 Customer Payment Amounts

TOTAL Customer Payment Amount:	**$ 256,815,000**
Slice Customer Payment Amount	**$ 58,111,585**
Non-Slice Customer Payment Amount	**$ 198,703,415**

Interest Rate	**1.56%**
Start Dart	**4/2/2008**
End Date	**9/30/2008**

		Non-Slice		Slice						INTEREST Calculation		
	Name	**Non-Slice Customer Percentage (%)**	**Customer Payment Amount ($$)**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice Customer Percentage**	**Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**Interim Payment Amount Not Taken**	**Interest Amount**	**Total True-Up Amount Including Interest**
10055	Albion, City of	0.0071%	$ 14,108	0.00000%	0.0000%	$ -	$ 14,108	$ 11,273	$ 2,835	$ -	$ -	$ 2,835
10005	Alder Mutual	0.0087%	$ 17,263	0.00000%	0.0000%	$ -	$ 17,263	$ 13,794	$ 3,469	$ -	$ -	$ 3,469
10057	Ashland, City of	0.4008%	$ 796,320	0.00000%	0.0000%	$ -	$ 796,320	$ 636,275	$ 160,045	$ -	$ -	$ 160,045
10015	Asotin County PUD #1	0.0108%	$ 21,376	0.00000%	0.0000%	$ -	$ 21,376	$ -	$ 21,376	$ 17,080	$ 132	$ 21,508
10059	Bandon, City of	0.1500%	$ 297,983	0.00000%	0.0000%	$ -	$ 297,983	$ 238,094	$ 59,889	$ -	$ -	$ 59,889
10024	Benton County PUD #1	1.7469%	$ 3,471,191	1.76410%	7.7962%	$ 4,530,473	$ 8,001,664	$ 6,426,261	$ 1,575,403	$ -	$ -	$ 1,575,403
10025	Benton REA	1.0501%	$ 2,086,558	0.00000%	0.0000%	$ -	$ 2,086,558	$ -	$ 2,086,558	$ 1,667,199	$ 12,897	$ 2,099,455
10027	Big Bend Elec Coop	0.8514%	$ 1,691,774	0.00000%	0.0000%	$ -	$ 1,691,774	$ 1,351,759	$ 340,015	$ -	$ -	$ 340,015
10028	Big Horn County Electric Coop.	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10029	Blachly Lane Elec Coop	0.0000%	$ -	0.06577%	0.2907%	$ 168,907	$ 168,907	$ 138,402	$ 30,505	$ -	$ -	$ 30,505
10061	Blaine, City of	0.1626%	$ 323,176	0.00000%	0.0000%	$ -	$ 323,176	$ 258,223	$ 64,953	$ -	$ -	$ 64,953
10062	Bonners Ferry, City of	0.1045%	$ 207,624	0.00000%	0.0000%	$ -	$ 207,624	$ 165,896	$ 41,728	$ -	$ -	$ 41,728
10064	Burley, City of	0.2602%	$ 516,989	0.00000%	0.0000%	$ -	$ 516,989	$ 413,084	$ 103,905	$ -	$ -	$ 103,905
10044	Canby, City of	0.3788%	$ 752,612	0.00000%	0.0000%	$ -	$ 752,612	$ -	$ 752,612	$ 601,351	$ 4,652	$ 757,264
10065	Cascade Locks, City of	0.0481%	$ 95,602	0.00000%	0.0000%	$ -	$ 95,602	$ 76,388	$ 19,214	$ -	$ -	$ 19,214
10046	Central Electric Coop	0.0000%	$ -	0.22965%	1.0149%	$ 589,776	$ 589,776	$ 483,260	$ 106,516	$ -	$ -	$ 106,516
10047	Central Lincoln PUD	2.7787%	$ 5,521,407	0.00000%	0.0000%	$ -	$ 5,521,407	$ -	$ 5,521,407	$ 4,411,707	$ 34,128	$ 5,555,535
10048	Central Montana Electric Power Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10066	Centralia, City of	0.4452%	$ 884,722	0.00000%	0.0000%	$ -	$ 884,722	$ -	$ 884,722	$ 706,910	$ 5,469	$ 890,191
10067	Cheney, City of	0.2793%	$ 555,048	0.00000%	0.0000%	$ -	$ 555,048	$ 443,494	$ 111,554	$ -	$ -	$ 111,554
10068	Chewelah, City of	0.0549%	$ 109,044	0.00000%	0.0000%	$ -	$ 109,044	$ 87,128	$ 21,916	$ -	$ -	$ 21,916
10101	Clallam County PUD #1	1.4370%	$ 2,855,293	0.00000%	0.0000%	$ -	$ 2,855,293	$ -	$ 2,855,293	$ 2,281,433	$ 17,649	$ 2,872,942
10103	Clark County PUD #1	7.8303%	$ 15,558,976	0.00000%	0.0000%	$ -	$ 15,558,976	$ 12,431,914	$ 3,127,062	$ -	$ -	$ 3,127,062
10105	Clatskanie PUD	0.7415%	$ 1,473,396	0.97550%	4.3111%	$ 2,505,230	$ 3,978,626	$ -	$ 3,978,626	$ 3,197,162	$ 24,733	$ 4,003,359
10106	Clearwater Power	0.0000%	$ -	0.08223%	0.3634%	$ 211,179	$ 211,179	$ 173,039	$ 38,140	$ -	$ -	$ 38,140
10109	Columbia Basin Elec Coop	0.1906%	$ 378,723	0.00000%	0.0000%	$ -	$ 378,723	$ 302,607	$ 76,116	$ -	$ -	$ 76,116
10111	Columbia Power Coop	0.0529%	$ 105,068	0.00000%	0.0000%	$ -	$ 105,068	$ 83,952	$ 21,116	$ -	$ -	$ 21,116
10113	Columbia REA	0.4788%	$ 951,448	0.00000%	0.0000%	$ -	$ 951,448	$ 760,225	$ 191,223	$ -	$ -	$ 191,223
10112	Columbia River PUD	1.1415%	$ 2,268,175	0.00000%	0.0000%	$ -	$ 2,268,175	$ 1,812,314	$ 455,861	$ -	$ -	$ 455,861
10116	Consolidated Irrigation District #19	0.0041%	$ 8,110	0.00000%	0.0000%	$ -	$ 8,110	$ 6,480	$ 1,630	$ -	$ -	$ 1,630
10118	Consumers Power	0.0000%	$ -	0.14518%	0.6416%	$ 372,844	$ 372,844	$ 305,508	$ 67,336	$ -	$ -	$ 67,336
10121	Coos Curry Elec Coop	0.0000%	$ -	0.13270%	0.5864%	$ 340,794	$ 340,794	$ 279,245	$ 61,549	$ -	$ -	$ 61,549
10378	Coulee Dam, City of	0.0422%	$ 83,944	0.00000%	0.0000%	$ -	$ 83,944	$ 67,073	$ 16,871	$ -	$ -	$ 16,871
10123	Cowlitz County PUD #1	9.2352%	$ 18,350,669	0.00000%	0.0000%	$ -	$ 18,350,669	$ 14,662,528	$ 3,688,141	$ -	$ -	$ 3,688,141
10070	Declo, City of	0.0067%	$ 13,321	0.00000%	0.0000%	$ -	$ 13,321	$ 10,643	$ 2,678	$ -	$ -	$ 2,678

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TOTAL Customer Payment Amount:	**$ 256,815,000**
Slice Customer Payment Amount	**$ 58,111,585**
Non-Slice Customer Payment Amount	**$ 198,703,415**

Interest Rate	**1.56%**
Start Dart	**4/2/2008**
End Date	**9/30/2008**

		Non-Slice		Slice						INTEREST Calculation		
	Name	**Non-Slice Customer Percentage (%)**	**Customer Payment Amount ($$)**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice Customer Percentage**	**Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**Interim Payment Amount Not Taken**	**Interest Amount**	**Total True-Up Amount Including Interest**
10136	Douglas Electric Cooperative	0.0000%	$ -	0.06518%	0.2881%	$ 167,392	$ 167,392	$ 137,160	$ 30,232	$ -	$ -	$ 30,232
10071	Drain, City of	0.0474%	$ 94,253	0.00000%	0.0000%	$ -	$ 94,253	$ -	$ 94,253	$ 75,310	$ 583	$ 94,836
10142	East End Mutual Electric	0.0414%	$ 82,308	0.00000%	0.0000%	$ -	$ 82,308	$ 65,766	$ 16,542	$ -	$ -	$ 16,542
10144	Eatonville, Town of	0.0646%	$ 128,388	0.00000%	0.0000%	$ -	$ 128,388	$ 102,584	$ 25,804	$ -	$ -	$ 25,804
10072	Ellensburg, City of	0.4584%	$ 910,764	0.00000%	0.0000%	$ -	$ 910,764	$ -	$ 910,764	$ 727,717	$ 5,630	$ 916,394
10156	Elmhurst Mutual P & L	0.6153%	$ 1,222,654	0.00000%	0.0000%	$ -	$ 1,222,654	$ 976,924	$ 245,730	$ -	$ -	$ 245,730
10157	Emerald County PUD	0.9955%	$ 1,978,118	0.00000%	0.0000%	$ -	$ 1,978,118	$ 1,580,554	$ 397,564	$ -	$ -	$ 397,564
10158	Energy Northwest	0.0548%	$ 108,843	0.00000%	0.0000%	$ -	$ 108,843	$ 86,968	$ 21,875	$ -	$ -	$ 21,875
10170	Eugene Water & Electric Board	2.1792%	$ 4,330,221	2.43280%	10.7514%	$ 6,247,795	$ 10,578,016	$ 8,497,319	$ 2,080,697	$ -	$ -	$ 2,080,697
10172	Fairchild AFB	0.1399%	$ 277,892	0.00000%	0.0000%	$ -	$ 277,892	$ -	$ 277,892	$ 222,041	$ 1,718	$ 279,610
10173	Fall River Elec Coop	0.0000%	$ -	0.07342%	0.3245%	$ 188,554	$ 188,554	$ 154,480	$ 34,074	$ -	$ -	$ 34,074
10174	Farmers Electric Company	0.0088%	$ 17,414	0.00000%	0.0000%	$ -	$ 17,414	$ 13,914	$ 3,500	$ -	$ -	$ 3,500
10177	Ferry County PUD #1	0.1439%	$ 285,873	0.00000%	0.0000%	$ -	$ 285,873	$ 228,418	$ 57,455	$ -	$ -	$ 57,455
10179	Flathead Elec Coop	3.1416%	$ 6,242,404	0.00000%	0.0000%	$ -	$ 6,242,404	$ 4,987,798	$ 1,254,606	$ -	$ -	$ 1,254,606
10074	Forest Grove, City of	0.5019%	$ 997,205	0.00000%	0.0000%	$ -	$ 997,205	$ 796,786	$ 200,419	$ -	$ -	$ 200,419
10183	Franklin County PUD #1	0.7915%	$ 1,572,670	0.78510%	3.4696%	$ 2,016,255	$ 3,588,925	$ 2,882,207	$ 706,718	$ -	$ -	$ 706,718
10186	Glacier Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10190	Grant County PUD #2	3.3715%	$ 6,699,315	0.00000%	0.0000%	$ -	$ 6,699,315	$ -	$ 6,699,315	$ 5,352,879	$ 41,409	$ 6,740,724
10191	Grays Harbor PUD #1	0.9751%	$ 1,937,493	1.16810%	5.1622%	$ 2,999,856	$ 4,937,349	$ -	$ 4,937,349	$ 3,966,741	$ 30,686	$ 4,968,035
10197	Harney Elec Coop	0.3309%	$ 657,507	0.00000%	0.0000%	$ -	$ 657,507	$ 525,360	$ 132,147	$ -	$ -	$ 132,147
10597	Hermiston, City of	0.2429%	$ 482,609	0.00000%	0.0000%	$ -	$ 482,609	$ 385,614	$ 96,995	$ -	$ -	$ 96,995
10076	Heyburn, City of	0.0845%	$ 167,984	0.00000%	0.0000%	$ -	$ 167,984	$ 134,222	$ 33,762	$ -	$ -	$ 33,762
10202	Hood River Elec Coop	0.2497%	$ 496,120	0.00000%	0.0000%	$ -	$ 496,120	$ 396,409	$ 99,711	$ -	$ -	$ 99,711
10203	Idaho County L & P	0.1055%	$ 209,554	0.00000%	0.0000%	$ -	$ 209,554	$ 167,437	$ 42,117	$ -	$ -	$ 42,117
10204	Idaho Falls Power	0.5428%	$ 1,078,601	0.69310%	3.0630%	$ 1,779,985	$ 2,858,586	$ 2,296,942	$ 561,644	$ -	$ -	$ 561,644
10209	Inland P & L	1.7547%	$ 3,486,648	0.00000%	0.0000%	$ -	$ 3,486,648	$ 2,785,897	$ 700,751	$ -	$ -	$ 700,751
10230	Kittitas County PUD #1	0.1455%	$ 289,077	0.00000%	0.0000%	$ -	$ 289,077	$ -	$ 289,077	$ 230,978	$ 1,787	$ 290,864
10231	Klickitat County PUD #1	0.5774%	$ 1,147,316	0.00000%	0.0000%	$ -	$ 1,147,316	$ -	$ 1,147,316	$ 916,727	$ 7,092	$ 1,154,408
10234	Kootenai Electric Coop	0.9003%	$ 1,788,848	0.00000%	0.0000%	$ -	$ 1,788,848	$ 1,429,323	$ 359,525	$ -	$ -	$ 359,525
10235	Lakeview L & P (WA)	0.6337%	$ 1,259,206	0.00000%	0.0000%	$ -	$ 1,259,206	$ 1,006,129	$ 253,077	$ -	$ -	$ 253,077
10236	Lane County Elec Coop	0.0000%	$ -	0.09464%	0.4182%	$ 243,050	$ 243,050	$ 199,154	$ 43,896	$ -	$ -	$ 43,896
10237	Lewis County PUD #1	2.0107%	$ 3,995,412	0.00000%	0.0000%	$ -	$ 3,995,412	$ 3,192,409	$ 803,003	$ -	$ -	$ 803,003
10239	Lincoln Elec Coop (MT)	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10242	Lost River Elec Coop	0.0000%	$ -	0.02456%	0.1085%	$ 63,074	$ 63,074	$ 51,682	$ 11,392	$ -	$ -	$ 11,392
10244	Lower Valley Energy	1.3295%	$ 2,641,817	0.00000%	0.0000%	$ -	$ 2,641,817	$ 2,110,861	$ 530,956	$ -	$ -	$ 530,956

Table 15.11

FY 2007-2008 Customer Payment Amounts

TOTAL Customer Payment Amount:	**$ 256,815,000**
Slice Customer Payment Amount	**$ 58,111,585**
Non-Slice Customer Payment Amount	**$ 198,703,415**

Interest Rate	**1.56%**
Start Dart	**4/2/2008**
End Date	**9/30/2008**

		Non-Slice		Slice						INTEREST Calculation		
	Name	**Non-Slice Customer Percentage (%)**	**Customer Payment Amount ($$)**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice Customer Percentage**	**Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**Interim Payment Amount Not Taken**	**Interest Amount**	**Total True-Up Amount Including Interest**
10246	Mason County PUD #1	0.1592%	$ 316,346	0.00000%	0.0000%	$ -	$ 316,346	$ -	$ 316,346	$ 252,766	$ 1,955	$ 318,301
10247	Mason County PUD #3	1.4700%	$ 2,920,880	0.00000%	0.0000%	$ -	$ 2,920,880	$ -	$ 2,920,880	$ 2,333,838	$ 18,054	$ 2,938,934
10078	McCleary, City of	0.0806%	$ 160,231	0.00000%	0.0000%	$ -	$ 160,231	$ 128,028	$ 32,203	$ -	$ -	$ 32,203
10079	McMinnville, City of	1.8703%	$ 3,716,312	0.00000%	0.0000%	$ -	$ 3,716,312	$ -	$ 3,716,312	$ 2,969,403	$ 22,971	$ 3,739,283
10256	Midstate Elec Coop	0.8012%	$ 1,592,053	0.00000%	0.0000%	$ -	$ 1,592,053	$ 1,272,081	$ 319,972	$ -	$ -	$ 319,972
10081	Milton Freewater, City of	0.1898%	$ 377,163	0.00000%	0.0000%	$ -	$ 377,163	$ 301,360	$ 75,803	$ -	$ -	$ 75,803
10080	Milton, City of	0.1414%	$ 281,049	0.00000%	0.0000%	$ -	$ 281,049	$ 224,563	$ 56,486	$ -	$ -	$ 56,486
10082	Minidoka, City of	0.0020%	$ 3,943	0.00000%	0.0000%	$ -	$ 3,943	$ 3,150	$ 793	$ -	$ -	$ 793
10258	Mission Valley	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10259	Missoula Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10260	Modern Elec Coop	0.5109%	$ 1,015,171	0.00000%	0.0000%	$ -	$ 1,015,171	$ 811,141	$ 204,030	$ -	$ -	$ 204,030
10083	Monmouth, City of	0.1547%	$ 307,368	0.00000%	0.0000%	$ -	$ 307,368	$ 245,593	$ 61,775	$ -	$ -	$ 61,775
10273	Nespelem Valley Elec Coop	0.0970%	$ 192,666	0.00000%	0.0000%	$ -	$ 192,666	$ 153,944	$ 38,722	$ -	$ -	$ 38,722
10278	Northern Lights	0.0000%	$ -	0.06418%	0.2836%	$ 164,824	$ 164,824	$ 135,056	$ 29,768	$ -	$ -	$ 29,768
10279	Northern Wasco County PUD	1.0661%	$ 2,118,368	0.00000%	0.0000%	$ -	$ 2,118,368	$ 1,692,616	$ 425,752	$ -	$ -	$ 425,752
10284	Ohop Mutual Light Company	0.1813%	$ 360,266	0.00000%	0.0000%	$ -	$ 360,266	$ 287,859	$ 72,407	$ -	$ -	$ 72,407
10285	Okanogan County Elec Coop	0.0000%	$ -	0.01822%	0.0805%	$ 46,792	$ 46,792	$ 38,341	$ 8,451	$ -	$ -	$ 8,451
10286	Okanogan County PUD #1	0.4121%	$ 818,889	0.49510%	2.1880%	$ 1,271,491	$ 2,090,380	$ 1,679,453	$ 410,927	$ -	$ -	$ 410,927
10288	Orcas P & L	0.4545%	$ 903,095	0.00000%	0.0000%	$ -	$ 903,095	$ 721,590	$ 181,505	$ -	$ -	$ 181,505
10291	Oregon Trail Coop	1.4519%	$ 2,884,943	0.00000%	0.0000%	$ -	$ 2,884,943	$ 2,305,124	$ 579,819	$ -	$ -	$ 579,819
10294	Pacific County PUD #2	0.6994%	$ 1,389,754	0.00000%	0.0000%	$ -	$ 1,389,754	$ -	$ 1,389,754	$ 1,110,440	$ 8,590	$ 1,398,344
10304	Parkland L & W	0.2721%	$ 540,639	0.00000%	0.0000%	$ -	$ 540,639	$ 431,981	$ 108,658	$ -	$ -	$ 108,658
10306	Pend Oreille County PUD #1	0.0301%	$ 59,904	0.38190%	1.6877%	$ 980,776	$ 1,040,680	$ 838,621	$ 202,059	$ -	$ -	$ 202,059
10307	Peninsula Light Company	1.2943%	$ 2,571,747	0.00000%	0.0000%	$ -	$ 2,571,747	$ 2,054,874	$ 516,873	$ -	$ -	$ 516,873
10086	Plummer, City of	0.0735%	$ 146,050	0.00000%	0.0000%	$ -	$ 146,050	$ 116,696	$ 29,354	$ -	$ -	$ 29,354
10298	PNGC	3.5409%	$ 7,035,850	2.80000%	12.3742%	$ 7,190,820	$ 14,226,670	$ 10,949,166	$ 3,277,504	$ -	$ -	$ 3,277,504
10087	Port Angeles, City of	1.5147%	$ 3,009,817	0.00000%	0.0000%	$ -	$ 3,009,817	$ 2,404,900	$ 604,917	$ -	$ -	$ 604,917
10706	Port of Seattle	0.3135%	$ 623,025	0.00000%	0.0000%	$ -	$ 623,025	$ -	$ 623,025	$ 497,809	$ 3,851	$ 626,876
10326	Puget Sound Naval Shipyard (Bremerton)	0.5284%	$ 1,050,039	0.00000%	0.0000%	$ -	$ 1,050,039	$ -	$ 1,050,039	$ 839,001	$ 6,490	$ 1,056,529
10331	Raft River Elec Coop	0.0000%	$ -	0.03948%	0.1745%	$ 101,391	$ 101,391	$ 83,079	$ 18,312	$ -	$ -	$ 18,312
10333	Ravalli County Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10089	Richland, City of	1.8510%	$ 3,677,978	0.00000%	0.0000%	$ -	$ 3,677,978	$ 2,938,774	$ 739,204	$ -	$ -	$ 739,204
10338	Riverside Elec Company	0.0375%	$ 74,509	0.00000%	0.0000%	$ -	$ 74,509	$ 59,534	$ 14,975	$ -	$ -	$ 14,975
10091	Rupert, City of	0.1678%	$ 333,415	0.00000%	0.0000%	$ -	$ 333,415	$ 266,405	$ 67,010	$ -	$ -	$ 67,010
10342	Salem Elec Coop	0.7583%	$ 1,506,774	0.00000%	0.0000%	$ -	$ 1,506,774	$ 1,203,941	$ 302,833	$ -	$ -	$ 302,833

Table 15.11

FY 2007-2008 Customer Payment Amounts

TOTAL Customer Payment Amount:	**$ 256,815,000**
Slice Customer Payment Amount	**$ 58,111,585**
Non-Slice Customer Payment Amount	**$ 198,703,415**

Interest Rate	**1.56%**
Start Dart	**4/2/2008**
End Date	**9/30/2008**

		Non-Slice		Slice						INTEREST Calculation		
	Name	**Non-Slice Customer Percentage (%)**	**Customer Payment Amount ($$)**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice Customer Percentage**	**Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**Interim Payment Amount Not Taken**	**Interest Amount**	**Total True-Up Amount Including Interest**
10343	Salmon River Elec Coop	0.0000%	$ -	0.07848%	0.3468%	$ 201,548	$ 201,548	$ 165,148	$ 36,400	$ -	$ -	$ 36,400
10349	Seattle City Light	4.8378%	$ 9,612,815	4.66760%	20.6277%	$ 11,987,097	$ 21,599,912	$ 17,345,470	$ 4,254,442	$ -	$ -	$ 4,254,442
10352	Skamania County PUD #1	0.2950%	$ 586,139	0.00000%	0.0000%	$ -	$ 586,139	$ -	$ 586,139	$ 468,336	$ 3,623	$ 589,762
10354	Snohomish County PUD #1	6.4801%	$ 12,876,111	4.99290%	22.0653%	$ 12,822,516	$ 25,698,627	$ 20,626,465	$ 5,072,162	$ -	$ -	$ 5,072,162
10094	Soda Springs, City of	0.0528%	$ 104,998	0.00000%	0.0000%	$ -	$ 104,998	$ 83,896	$ 21,102	$ -	$ -	$ 21,102
11342	Southern MT G&T	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10360	South Side Electric	0.0999%	$ 198,442	0.00000%	0.0000%	$ -	$ 198,442	$ 158,559	$ 39,883	$ -	$ -	$ 39,883
10363	Springfield Utility Board	1.8601%	$ 3,696,068	0.00000%	0.0000%	$ -	$ 3,696,068	$ 2,953,228	$ 742,840	$ -	$ -	$ 742,840
10379	Steilacoom, Town of	0.0922%	$ 183,136	0.00000%	0.0000%	$ -	$ 183,136	$ 146,329	$ 36,807	$ -	$ -	$ 36,807
10095	Sumas, City of	0.0664%	$ 131,939	0.00000%	0.0000%	$ -	$ 131,939	$ 105,422	$ 26,517	$ -	$ -	$ 26,517
10369	Surprise Valley Elec Coop	0.2584%	$ 513,481	0.00000%	0.0000%	$ -	$ 513,481	$ 410,281	$ 103,200	$ -	$ -	$ 103,200
10370	Tacoma Public Utilities	8.1628%	$ 16,219,756	0.00000%	0.0000%	$ -	$ 16,219,756	$ 12,959,889	$ 3,259,867	$ -	$ -	$ 3,259,867
10371	Tanner Elec Coop	0.1565%	$ 310,975	0.00000%	0.0000%	$ -	$ 310,975	$ 248,475	$ 62,500	$ -	$ -	$ 62,500
10376	Tillamook PUD #1	0.9893%	$ 1,965,785	0.00000%	0.0000%	$ -	$ 1,965,785	$ 1,570,699	$ 395,086	$ -	$ -	$ 395,086
10097	Troy, City of	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10406	U.S. DOE Albany	0.0086%	$ 17,147	0.00000%	0.0000%	$ -	$ 17,147	$ -	$ 17,147	$ 13,701	$ 106	$ 17,253
10408	U.S. Naval Station, Everett (Jim Creek)	0.0276%	$ 54,829	0.00000%	0.0000%	$ -	$ 54,829	$ -	$ 54,829	$ 43,809	$ 339	$ 55,168
10409	U.S. Naval Submarine Base, Bangor	0.3740%	$ 743,057	0.00000%	0.0000%	$ -	$ 743,057	$ -	$ 743,057	$ 593,716	$ 4,593	$ 747,650
10388	Umatilla Elec Coop	0.0000%	$ -	0.32749%	1.4473%	$ 841,043	$ 841,043	$ 689,148	$ 151,895	$ -	$ -	$ 151,895
10482	Umpqua Indian Utility Cooperative	0.0469%	$ 93,097	0.00000%	0.0000%	$ -	$ 93,097	$ 74,387	$ 18,710	$ -	$ -	$ 18,710
10391	United Electric Coop	0.3739%	$ 742,911	0.00000%	0.0000%	$ -	$ 742,911	$ 593,600	$ 149,311	$ -	$ -	$ 149,311
10399	USBIA Wapato	0.0307%	$ 61,006	0.00000%	0.0000%	$ -	$ 61,006	$ -	$ 61,006	$ 48,745	$ 377	$ 61,383
10426	USDOE-Richland	0.3941%	$ 783,131	0.00000%	0.0000%	$ -	$ 783,131	$ -	$ 783,131	$ 625,736	$ 4,841	$ 787,972
10434	Vera Irrigation District	0.5048%	$ 1,003,023	0.00000%	0.0000%	$ -	$ 1,003,023	$ 801,434	$ 201,589	$ -	$ -	$ 201,589
10436	Vigilante Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10440	Wahkiakum County PUD #1	0.0924%	$ 183,689	0.00000%	0.0000%	$ -	$ 183,689	$ 146,771	$ 36,918	$ -	$ -	$ 36,918
10442	Wasco Elec Coop	0.2098%	$ 416,946	0.00000%	0.0000%	$ -	$ 416,946	$ 333,148	$ 83,798	$ -	$ -	$ 83,798
11680	Weiser, City of	0.0559%	$ 111,056	0.00000%	0.0000%	$ -	$ 111,056	$ 88,736	$ 22,320	$ -	$ -	$ 22,320
10446	Wells Rural Electric Company	1.5734%	$ 3,126,424	0.00000%	0.0000%	$ -	$ 3,126,424	$ 2,498,072	$ 628,352	$ -	$ -	$ 628,352
10448	West Oregon Elec Coop	0.0000%	$ -	0.03042%	0.1344%	$ 78,123	$ 78,123	$ 64,014	$ 14,109	$ -	$ -	$ 14,109
10451	Whatcom County PUD #1	0.4181%	$ 830,852	0.00000%	0.0000%	$ -	$ 830,852	$ 663,866	$ 166,986	$ -	$ -	$ 166,986
10502	Yakama Power	0.0765%	$ 151,920	0.00000%	0.0000%	$ -	$ 151,920	$ -	$ 151,920	$ 121,387	$ 939	$ 152,859
	TOTAL	**100%**	**$ 198,703,411**	**22.6278%**	**100%**	**$ 58,111,585**	**$ 256,814,996**	**$ 170,906,083**	**$ 85,908,913**	**$ 34,293,922**	**$ 265,294**	**$ 86,174,207**

ERRATA

Errata to
WP-07 Supplemental Power Rate Case
FY 2002-2008 Lookback Study
WP-07-FS-BPA-08

Page 250, Table 11.5

Change number in 3rd column for Avista from "51.10" to "51.45".

Page 262, Table 14.2

Change numbers for 2nd and 3rd columns for Avista from "33,516" and "52,092" to "34,900" and "53,477"

Change numbers for 2nd and 3rd columns for Total from "301,055" and "473,569" to "302,440" and "474,954".

Page 267, Line 9

Change "$16.53" to "$15.09".

Table 15.2

Change numbers starting with the second row in the last column from "$33.516", "$33.516", "$2.213" and "$16.531" to "$34.900", "$34.900", "$2.156" and "$15.089".

Page 271, Line 21

Change "FY 2009 is estimated to be $178.39 million." to "FY 2009 is estimated to be $179.12 million.".

Page 272, Table 15.5

Change the numbers in the 1st and 2nd column for Avista from "$33.516" and "$33.516" to "$34.900" and "$34.900".

Change the numbers in the 1st and 2nd column for Totals from "301.055" and "33.516" to "302.440" and "34.900".

Page 273, Line 25

Change "assumptions is $70.769 million." to "assumptions is $71.487 million."

Page 274, Table 15.6

Change numbers in the 2nd, 3rd, 4th, 5th and 6th columns for Avista from "$5.560", "$2.571", "$2.989", "54%" and "$76.517" to "$7.002", "$3.289", "$3.712", "53%" and "$75.659".

Change numbers in the 2nd, 3rd, 4th and 6th columns for Total from "$249.161", "$70.769", "$178.392", and "$637.195" to "$250.603", "$71.487", "$179.116", and "$636.338".

Page 282-284, Table 15.9

Page 282, Change numbers in column K, rows 4 and 5 from “$33.516” and “$33.516” to “$34.900” and “$34.900”.

Page 284, Change numbers in column K, rows 64 and 65 from “$301.055” and “$33.516” to “$302.440” and “$34.900”.

Page 289-292, Table 15.11

Replace Table 15.11, Pages 289-292 with attached Table 15.11, Pages 289-292 Conformed Version.

Conformed Version

Table 15.11
FY 2007-2008 Customer Payment Amounts

TOTAL Customer Payment Amount:	**$ 256,815,000**
Slice Customer Payment Amount	**$ 58,111,585**
Non-Slice Customer Payment Amount	**$ 198,703,415**

INTEREST Calculation	
Interest Rate	**1.56%**
Start Dart	**4/2/2008**
End Date	**9/30/2008**

		Non-Slice		Slice						INTEREST Calculation		
	Name	**Non-Slice Customer Percentage (%)**	**Non-Slice Customer Payment Amount ($$)**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice Customer Percentage**	**Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**Interim Payment Amount Not Taken**	**Interest Amount**	**Total True-Up Amount Including Interest**
10055	Albion, City of	0.0074%	$ 14,625	0.00000%	0.0000%	$ -	$ 14,625	$ 11,273	$ 3,352	$ -	$ -	$ 3,352
10005	Alder Mutual	0.0087%	$ 17,199	0.00000%	0.0000%	$ -	$ 17,199	$ 13,794	$ 3,405	$ -	$ -	$ 3,405
10057	Ashland, City of	0.3992%	$ 793,196	0.00000%	0.0000%	$ -	$ 793,196	$ 636,275	$ 156,921	$ -	$ -	$ 156,921
10015	Asotin County PUD #1	0.0107%	$ 21,293	0.00000%	0.0000%	$ -	$ 21,293	$ -	$ 21,293	$ 17,080	$ 132	$ 21,425
10059	Bandon, City of	0.1493%	$ 296,751	0.00000%	0.0000%	$ -	$ 296,751	$ 238,094	$ 58,657	$ -	$ -	$ 58,657
10024	Benton County PUD #1	1.7391%	$ 3,455,748	1.76410%	7.7962%	$ 4,530,473	$ 7,986,221	$ 6,426,261	$ 1,559,960	$ -	$ -	$ 1,559,960
10025	Benton REA	1.0461%	$ 2,078,680	0.00000%	0.0000%	$ -	$ 2,078,680	$ -	$ 2,078,680	$ 1,667,199	$ 12,897	$ 2,091,577
10027	Big Bend Elec Coop	0.8335%	$ 1,656,264	0.00000%	0.0000%	$ -	$ 1,656,264	$ 1,351,759	$ 304,505	$ -	$ -	$ 304,505
10028	Big Horn County Electric Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10029	Blachly Lane Elec Coop	0.0000%	$ -	0.06577%	0.2907%	$ 168,907	$ 168,907	$ 138,402	$ 30,505	$ -	$ -	$ 30,505
10061	Blaine, City of	0.1620%	$ 321,885	0.00000%	0.0000%	$ -	$ 321,885	$ 258,223	$ 63,662	$ -	$ -	$ 63,662
10062	Bonners Ferry, City of	0.1041%	$ 206,761	0.00000%	0.0000%	$ -	$ 206,761	$ 165,896	$ 40,865	$ -	$ -	$ 40,865
10064	Burley, City of	0.2591%	$ 514,856	0.00000%	0.0000%	$ -	$ 514,856	$ 413,084	$ 101,772	$ -	$ -	$ 101,772
10044	Canby, City of	0.3772%	$ 749,604	0.00000%	0.0000%	$ -	$ 749,604	$ -	$ 749,604	$ 601,351	$ 4,652	$ 754,256
10065	Cascade Locks, City of	0.0479%	$ 95,219	0.00000%	0.0000%	$ -	$ 95,219	$ 76,388	$ 18,831	$ -	$ -	$ 18,831
10046	Central Electric Coop	0.0000%	$ -	0.22965%	1.0149%	$ 589,776	$ 589,776	$ 483,260	$ 106,516	$ -	$ -	$ 106,516
10047	Central Lincoln PUD	2.7671%	$ 5,498,411	0.00000%	0.0000%	$ -	$ 5,498,411	$ -	$ 5,498,411	$ 4,411,707	$ 34,128	$ 5,532,539
10048	Central Montana Electric Power Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10066	Centralia, City of	0.4436%	$ 881,385	0.00000%	0.0000%	$ -	$ 881,385	$ -	$ 881,385	$ 706,910	$ 5,469	$ 886,854
10067	Cheney, City of	0.2832%	$ 562,692	0.00000%	0.0000%	$ -	$ 562,692	$ 443,494	$ 119,198	$ -	$ -	$ 119,198
10068	Chewelah, City of	0.0547%	$ 108,600	0.00000%	0.0000%	$ -	$ 108,600	$ 87,128	$ 21,472	$ -	$ -	$ 21,472
10101	Clallam County PUD #1	1.4273%	$ 2,836,063	0.00000%	0.0000%	$ -	$ 2,836,063	$ -	$ 2,836,063	$ 2,281,433	$ 17,649	$ 2,853,712
10103	Clark County PUD #1	7.7965%	$ 15,491,862	0.00000%	0.0000%	$ -	$ 15,491,862	$ 12,431,914	$ 3,059,948	$ -	$ -	$ 3,059,948
10105	Clatskanie PUD	0.7387%	$ 1,467,873	0.97550%	4.3111%	$ 2,505,230	$ 3,973,103	$ -	$ 3,973,103	$ 3,197,162	$ 24,733	$ 3,997,836
10106	Clearwater Power	0.0000%	$ -	0.08223%	0.3634%	$ 211,179	$ 211,179	$ 173,039	$ 38,140	$ -	$ -	$ 38,140
10109	Columbia Basin Elec Coop	0.1898%	$ 377,138	0.00000%	0.0000%	$ -	$ 377,138	$ 302,607	$ 74,531	$ -	$ -	$ 74,531
10111	Columbia Power Coop	0.0527%	$ 104,631	0.00000%	0.0000%	$ -	$ 104,631	$ 83,952	$ 20,679	$ -	$ -	$ 20,679
10113	Columbia REA	0.4768%	$ 947,343	0.00000%	0.0000%	$ -	$ 947,343	$ 760,225	$ 187,118	$ -	$ -	$ 187,118
10112	Columbia River PUD	1.1374%	$ 2,260,096	0.00000%	0.0000%	$ -	$ 2,260,096	$ 1,812,314	$ 447,782	$ -	$ -	$ 447,782
10116	Consolidated Irrigation District #19	0.0041%	$ 8,082	0.00000%	0.0000%	$ -	$ 8,082	$ 6,480	$ 1,602	$ -	$ -	$ 1,602
10118	Consumers Power	0.0000%	$ -	0.14518%	0.6416%	$ 372,844	$ 372,844	$ 305,508	$ 67,336	$ -	$ -	$ 67,336
10121	Coos Curry Elec Coop	0.0000%	$ -	0.13270%	0.5864%	$ 340,794	$ 340,794	$ 279,245	$ 61,549	$ -	$ -	$ 61,549
10378	Coulee Dam, City of	0.0421%	$ 83,620	0.00000%	0.0000%	$ -	$ 83,620	$ 67,073	$ 16,547	$ -	$ -	$ 16,547
10123	Cowlitz County PUD #1	9.4330%	$ 18,743,735	0.00000%	0.0000%	$ -	$ 18,743,735	$ 14,662,528	$ 4,081,207	$ -	$ -	$ 4,081,207
10070	Declo, City of	0.0067%	$ 13,267	0.00000%	0.0000%	$ -	$ 13,267	$ 10,643	$ 2,624	$ -	$ -	$ 2,624

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TOTAL Customer Payment Amount:	**$ 256,815,000**
Slice Customer Payment Amount	**$ 58,111,585**
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Interest Rate	**1.56%**
Start Dart	**4/2/2008**
End Date	**9/30/2008**

		Non-Slice		Slice						INTEREST Calculation		
	Name	**Non-Slice Customer Percentage (%)**	**Non-Slice Customer Payment Amount ($$)**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice Customer Percentage**	**Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**Interim Payment Amount Not Taken**	**Interest Amount**	**Total True-Up Amount Including Interest**
10136	Douglas Electric Cooperative	0.0000%	$ -	0.06518%	0.2881%	$ 167,392	$ 167,392	$ 137,160	$ 30,232	$ -	$ -	$ 30,232
10071	Drain, City of	0.0472%	$ 93,874	0.00000%	0.0000%	$ -	$ 93,874	$ -	$ 93,874	$ 75,310	$ 583	$ 94,457
10142	East End Mutual Electric	0.0412%	$ 81,932	0.00000%	0.0000%	$ -	$ 81,932	$ 65,766	$ 16,166	$ -	$ -	$ 16,166
10144	Eatonville, Town of	0.0644%	$ 127,868	0.00000%	0.0000%	$ -	$ 127,868	$ 102,584	$ 25,284	$ -	$ -	$ 25,284
10072	Ellensburg, City of	0.4564%	$ 906,968	0.00000%	0.0000%	$ -	$ 906,968	$ -	$ 906,968	$ 727,717	$ 5,630	$ 912,598
10156	Elmhurst Mutual P & L	0.6129%	$ 1,217,866	0.00000%	0.0000%	$ -	$ 1,217,866	$ 976,924	$ 240,942	$ -	$ -	$ 240,942
10157	Emerald County PUD	0.9923%	$ 1,971,795	0.00000%	0.0000%	$ -	$ 1,971,795	$ 1,580,554	$ 391,241	$ -	$ -	$ 391,241
10158	Energy Northwest	0.0564%	$ 112,147	0.00000%	0.0000%	$ -	$ 112,147	$ 86,968	$ 25,179	$ -	$ -	$ 25,179
10170	Eugene Water & Electric Board	2.1713%	$ 4,314,511	2.43280%	10.7514%	$ 6,247,795	$ 10,562,306	$ 8,497,319	$ 2,064,987	$ -	$ -	$ 2,064,987
10172	Fairchild AFB	0.1393%	$ 276,864	0.00000%	0.0000%	$ -	$ 276,864	$ -	$ 276,864	$ 222,041	$ 1,718	$ 278,582
10173	Fall River Elec Coop	0.0000%	$ -	0.07342%	0.3245%	$ 188,554	$ 188,554	$ 154,480	$ 34,074	$ -	$ -	$ 34,074
10174	Farmers Electric Company	0.0092%	$ 18,267	0.00000%	0.0000%	$ -	$ 18,267	$ 13,914	$ 4,353	$ -	$ -	$ 4,353
10177	Ferry County PUD #1	0.1434%	$ 284,984	0.00000%	0.0000%	$ -	$ 284,984	$ 228,418	$ 56,566	$ -	$ -	$ 56,566
10179	Flathead Elec Coop	3.1291%	$ 6,217,707	0.00000%	0.0000%	$ -	$ 6,217,707	$ 4,987,798	$ 1,229,909	$ -	$ -	$ 1,229,909
10074	Forest Grove, City of	0.4994%	$ 992,360	0.00000%	0.0000%	$ -	$ 992,360	$ 796,786	$ 195,574	$ -	$ -	$ 195,574
10183	Franklin County PUD #1	0.7811%	$ 1,552,015	0.78510%	3.4696%	$ 2,016,255	$ 3,568,270	$ 2,882,207	$ 686,063	$ -	$ -	$ 686,063
10186	Glacier Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10190	Grant County PUD #2	3.3592%	$ 6,674,904	0.00000%	0.0000%	$ -	$ 6,674,904	$ -	$ 6,674,904	$ 5,352,879	$ 41,409	$ 6,716,313
10191	Grays Harbor PUD #1	0.9714%	$ 1,930,144	1.16810%	5.1622%	$ 2,999,856	$ 4,930,000	$ -	$ 4,930,000	$ 3,966,741	$ 30,686	$ 4,960,686
10197	Harney Elec Coop	0.3291%	$ 653,851	0.00000%	0.0000%	$ -	$ 653,851	$ 525,360	$ 128,491	$ -	$ -	$ 128,491
10597	Hermiston, City of	0.2419%	$ 480,627	0.00000%	0.0000%	$ -	$ 480,627	$ 385,614	$ 95,013	$ -	$ -	$ 95,013
10076	Heyburn, City of	0.0843%	$ 167,491	0.00000%	0.0000%	$ -	$ 167,491	$ 134,222	$ 33,269	$ -	$ -	$ 33,269
10202	Hood River Elec Coop	0.2487%	$ 494,086	0.00000%	0.0000%	$ -	$ 494,086	$ 396,409	$ 97,677	$ -	$ -	$ 97,677
10203	Idaho County L & P	0.1050%	$ 208,727	0.00000%	0.0000%	$ -	$ 208,727	$ 167,437	$ 41,290	$ -	$ -	$ 41,290
10204	Idaho Falls Power	0.5408%	$ 1,074,509	0.69310%	3.0630%	$ 1,779,985	$ 2,854,494	$ 2,296,942	$ 557,552	$ -	$ -	$ 557,552
10209	Inland P & L	1.7497%	$ 3,476,661	0.00000%	0.0000%	$ -	$ 3,476,661	$ 2,785,897	$ 690,764	$ -	$ -	$ 690,764
10230	Kittitas County PUD #1	0.1451%	$ 288,327	0.00000%	0.0000%	$ -	$ 288,327	$ -	$ 288,327	$ 230,978	$ 1,787	$ 290,114
10231	Klickitat County PUD #1	0.5827%	$ 1,157,776	0.00000%	0.0000%	$ -	$ 1,157,776	$ -	$ 1,157,776	$ 916,727	$ 7,092	$ 1,164,868
10234	Kootenai Electric Coop	0.8969%	$ 1,782,094	0.00000%	0.0000%	$ -	$ 1,782,094	$ 1,429,323	$ 352,771	$ -	$ -	$ 352,771
10235	Lakeview L & P (WA)	0.6313%	$ 1,254,338	0.00000%	0.0000%	$ -	$ 1,254,338	$ 1,006,129	$ 248,209	$ -	$ -	$ 248,209
10236	Lane County Elec Coop	0.0000%	$ -	0.09464%	0.4182%	$ 243,050	$ 243,050	$ 199,154	$ 43,896	$ -	$ -	$ 43,896
10237	Lewis County PUD #1	2.0045%	$ 3,982,952	0.00000%	0.0000%	$ -	$ 3,982,952	$ 3,192,409	$ 790,543	$ -	$ -	$ 790,543
10239	Lincoln Elec Coop (MT)	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10242	Lost River Elec Coop	0.0000%	$ -	0.02456%	0.1085%	$ 63,074	$ 63,074	$ 51,682	$ 11,392	$ -	$ -	$ 11,392
10244	Lower Valley Energy	1.4683%	$ 2,917,624	0.00000%	0.0000%	$ -	$ 2,917,624	$ 2,110,861	$ 806,763	$ -	$ -	$ 806,763

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Slice Customer Payment Amount	**$ 58,111,585**
Non-Slice Customer Payment Amount	**$ 198,703,415**

Interest Rate	**1.56%**
Start Dart	**4/2/2008**
End Date	**9/30/2008**

		Non-Slice		**Slice**						**INTEREST Calculation**		
	Name	**Non-Slice Customer Percentage (%)**	**Non-Slice Customer Payment Amount ($$)**	**Slice Percent (Retained Slice for PNGC Members)**	**Slice Customer Percentage**	**Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**Interim Payment Amount Not Taken**	**Interest Amount**	**Total True-Up Amount Including Interest**
10246	Mason County PUD #1	0.1586%	$ 315,079	0.00000%	0.0000%	$ -	$ 315,079	$ -	$ 315,079	$ 252,766	$ 1,955	$ 317,034
10247	Mason County PUD #3	1.4644%	$ 2,909,772	0.00000%	0.0000%	$ -	$ 2,909,772	$ -	$ 2,909,772	$ 2,333,838	$ 18,054	$ 2,927,826
10078	McCleary, City of	0.0803%	$ 159,640	0.00000%	0.0000%	$ -	$ 159,640	$ 128,028	$ 31,612	$ -	$ -	$ 31,612
10079	McMinnville, City of	1.8631%	$ 3,701,989	0.00000%	0.0000%	$ -	$ 3,701,989	$ -	$ 3,701,989	$ 2,969,403	$ 22,971	$ 3,724,960
10256	Midstate Elec Coop	0.7980%	$ 1,585,686	0.00000%	0.0000%	$ -	$ 1,585,686	$ 1,272,081	$ 313,605	$ -	$ -	$ 313,605
10081	Milton Freewater, City of	0.1884%	$ 374,393	0.00000%	0.0000%	$ -	$ 374,393	$ 301,360	$ 73,033	$ -	$ -	$ 73,033
10080	Milton, City of	0.1409%	$ 279,935	0.00000%	0.0000%	$ -	$ 279,935	$ 224,563	$ 55,372	$ -	$ -	$ 55,372
10082	Minidoka, City of	0.0020%	$ 3,915	0.00000%	0.0000%	$ -	$ 3,915	$ 3,150	$ 765	$ -	$ -	$ 765
10258	Mission Valley	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10259	Missoula Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10260	Modern Elec Coop	0.5073%	$ 1,008,040	0.00000%	0.0000%	$ -	$ 1,008,040	$ 811,141	$ 196,899	$ -	$ -	$ 196,899
10083	Monmouth, City of	0.1541%	$ 306,119	0.00000%	0.0000%	$ -	$ 306,119	$ 245,593	$ 60,526	$ -	$ -	$ 60,526
10273	Nespelem Valley Elec Coop	0.0966%	$ 191,918	0.00000%	0.0000%	$ -	$ 191,918	$ 153,944	$ 37,974	$ -	$ -	$ 37,974
10278	Northern Lights	0.0000%	$ -	0.06418%	0.2836%	$ 164,824	$ 164,824	$ 135,056	$ 29,768	$ -	$ -	$ 29,768
10279	Northern Wasco County PUD	1.0742%	$ 2,134,571	0.00000%	0.0000%	$ -	$ 2,134,571	$ 1,692,616	$ 441,955	$ -	$ -	$ 441,955
10284	Ohop Mutual Light Company	0.1806%	$ 358,914	0.00000%	0.0000%	$ -	$ 358,914	$ 287,859	$ 71,055	$ -	$ -	$ 71,055
10285	Okanogan County Elec Coop	0.0000%	$ -	0.01822%	0.0805%	$ 46,792	$ 46,792	$ 38,341	$ 8,451	$ -	$ -	$ 8,451
10286	Okanogan County PUD #1	0.4106%	$ 815,926	0.49510%	2.1880%	$ 1,271,491	$ 2,087,417	$ 1,679,453	$ 407,964	$ -	$ -	$ 407,964
10288	Orcas P & L	0.4528%	$ 899,803	0.00000%	0.0000%	$ -	$ 899,803	$ 721,590	$ 178,213	$ -	$ -	$ 178,213
10291	Oregon Trail Coop	1.4458%	$ 2,872,930	0.00000%	0.0000%	$ -	$ 2,872,930	$ 2,305,124	$ 567,806	$ -	$ -	$ 567,806
10294	Pacific County PUD #2	0.6968%	$ 1,384,577	0.00000%	0.0000%	$ -	$ 1,384,577	$ -	$ 1,384,577	$ 1,110,440	$ 8,590	$ 1,393,167
10304	Parkland L & W	0.2710%	$ 538,544	0.00000%	0.0000%	$ -	$ 538,544	$ 431,981	$ 106,563	$ -	$ -	$ 106,563
10306	Pend Oreille County PUD #1	0.0300%	$ 59,698	0.38190%	1.6877%	$ 980,776	$ 1,040,474	$ 838,621	$ 201,853	$ -	$ -	$ 201,853
10307	Peninsula Light Company	1.2892%	$ 2,561,685	0.00000%	0.0000%	$ -	$ 2,561,685	$ 2,054,874	$ 506,811	$ -	$ -	$ 506,811
10086	Plummer, City of	0.0732%	$ 145,449	0.00000%	0.0000%	$ -	$ 145,449	$ 116,696	$ 28,753	$ -	$ -	$ 28,753
10298	PNGC	3.5305%	$ 7,015,233	2.80000%	12.3742%	$ 7,190,820	$ 14,206,053	$ 10,949,166	$ 3,256,887	$ -	$ -	$ 3,256,887
10087	Port Angeles, City of	1.4986%	$ 2,977,858	0.00000%	0.0000%	$ -	$ 2,977,858	$ 2,404,900	$ 572,958	$ -	$ -	$ 572,958
10706	Port of Seattle	0.3124%	$ 620,680	0.00000%	0.0000%	$ -	$ 620,680	$ -	$ 620,680	$ 497,809	$ 3,851	$ 624,531
10326	Puget Sound Naval Shipyard (Bremerton)	0.5264%	$ 1,045,970	0.00000%	0.0000%	$ -	$ 1,045,970	$ -	$ 1,045,970	$ 839,001	$ 6,490	$ 1,052,460
10331	Raft River Elec Coop	0.0000%	$ -	0.03948%	0.1745%	$ 101,391	$ 101,391	$ 83,079	$ 18,312	$ -	$ -	$ 18,312
10333	Ravalli County Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10089	Richland, City of	1.8434%	$ 3,662,901	0.00000%	0.0000%	$ -	$ 3,662,901	$ 2,938,774	$ 724,127	$ -	$ -	$ 724,127
10338	Riverside Elec Company	0.0374%	$ 74,225	0.00000%	0.0000%	$ -	$ 74,225	$ 59,534	$ 14,691	$ -	$ -	$ 14,691
10091	Rupert, City of	0.1634%	$ 324,761	0.00000%	0.0000%	$ -	$ 324,761	$ 266,405	$ 58,356	$ -	$ -	$ 58,356
10342	Salem Elec Coop	0.7552%	$ 1,500,534	0.00000%	0.0000%	$ -	$ 1,500,534	$ 1,203,941	$ 296,593	$ -	$ -	$ 296,593

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	Name	**Non-Slice: Non-Slice Customer Percentage (%)**	**Non-Slice: Non-Slice Customer Payment Amount ($$)**	**Slice: Slice Percent (Retained Slice for PNGC Members)**	**Slice: Slice Customer Percentage**	**Slice: Slice Customer Payment Amount**	**TOTAL Customer Payment Amount**	**Total Interim Payments Disbursed**	**Interim Agreement True-Up Amount**	**INTEREST Calculation: Interim Payment Amount Not Taken**	**INTEREST Calculation: Interest Amount**	**Total True-Up Amount Including Interest**
10343	Salmon River Elec Coop	0.0000%	$ -	0.07848%	0.3468%	$ 201,548	$ 201,548	$ 165,148	$ 36,400	$ -	$ -	$ 36,400
10349	Seattle City Light	4.8180%	$ 9,573,544	4.66760%	20.6277%	$ 11,987,097	$ 21,560,641	$ 17,345,470	$ 4,215,171	$ -	$ -	$ 4,215,171
10352	Skamania County PUD #1	0.2938%	$ 583,843	0.00000%	0.0000%	$ -	$ 583,843	$ -	$ 583,843	$ 468,336	$ 3,623	$ 587,466
10354	Snohomish County PUD #1	6.4554%	$ 12,827,039	4.99290%	22.0653%	$ 12,822,516	$ 25,649,555	$ 20,626,465	$ 5,023,090	$ -	$ -	$ 5,023,090
10094	Soda Springs, City of	0.0553%	$ 109,786	0.00000%	0.0000%	$ -	$ 109,786	$ 83,896	$ 25,890	$ -	$ -	$ 25,890
11342	Southern MT G&T	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10360	South Side Electric	0.0994%	$ 197,479	0.00000%	0.0000%	$ -	$ 197,479	$ 158,559	$ 38,920	$ -	$ -	$ 38,920
10363	Springfield Utility Board	1.8535%	$ 3,683,043	0.00000%	0.0000%	$ -	$ 3,683,043	$ 2,953,228	$ 729,815	$ -	$ -	$ 729,815
10379	Steilacoom, Town of	0.0918%	$ 182,392	0.00000%	0.0000%	$ -	$ 182,392	$ 146,329	$ 36,063	$ -	$ -	$ 36,063
10095	Sumas, City of	0.0662%	$ 131,575	0.00000%	0.0000%	$ -	$ 131,575	$ 105,422	$ 26,153	$ -	$ -	$ 26,153
10369	Surprise Valley Elec Coop	0.2572%	$ 511,023	0.00000%	0.0000%	$ -	$ 511,023	$ 410,281	$ 100,742	$ -	$ -	$ 100,742
10370	Tacoma Public Utilities	8.1308%	$ 16,156,113	0.00000%	0.0000%	$ -	$ 16,156,113	$ 12,959,889	$ 3,196,224	$ -	$ -	$ 3,196,224
10371	Tanner Elec Coop	0.1559%	$ 309,706	0.00000%	0.0000%	$ -	$ 309,706	$ 248,475	$ 61,231	$ -	$ -	$ 61,231
10376	Tillamook PUD #1	0.9852%	$ 1,957,706	0.00000%	0.0000%	$ -	$ 1,957,706	$ 1,570,699	$ 387,007	$ -	$ -	$ 387,007
10097	Troy, City of	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10406	U.S. DOE Albany	0.0086%	$ 17,076	0.00000%	0.0000%	$ -	$ 17,076	$ -	$ 17,076	$ 13,701	$ 106	$ 17,182
10408	U.S. Naval Station, Everett (Jim Creek)	0.0273%	$ 54,170	0.00000%	0.0000%	$ -	$ 54,170	$ -	$ 54,170	$ 43,809	$ 339	$ 54,509
10409	U.S. Naval Submarine Base, Bangor	0.3725%	$ 740,217	0.00000%	0.0000%	$ -	$ 740,217	$ -	$ 740,217	$ 593,716	$ 4,593	$ 744,810
10388	Umatilla Elec Coop	0.0000%	$ -	0.32749%	1.4473%	$ 841,043	$ 841,043	$ 689,148	$ 151,895	$ -	$ -	$ 151,895
10482	Umpqua Indian Utility Cooperative	0.0467%	$ 92,885	0.00000%	0.0000%	$ -	$ 92,885	$ 74,387	$ 18,498	$ -	$ -	$ 18,498
10391	United Electric Coop	0.3723%	$ 739,810	0.00000%	0.0000%	$ -	$ 739,810	$ 593,600	$ 146,210	$ -	$ -	$ 146,210
10399	USBIA Wapato	0.0305%	$ 60,578	0.00000%	0.0000%	$ -	$ 60,578	$ -	$ 60,578	$ 48,745	$ 377	$ 60,955
10426	USDOE-Richland	0.3935%	$ 781,929	0.00000%	0.0000%	$ -	$ 781,929	$ -	$ 781,929	$ 625,736	$ 4,841	$ 786,770
10434	Vera Irrigation District	0.5027%	$ 998,939	0.00000%	0.0000%	$ -	$ 998,939	$ 801,434	$ 197,505	$ -	$ -	$ 197,505
10436	Vigilante Elec Coop	0.0000%	$ -	0.00000%	0.0000%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10440	Wahkiakum County PUD #1	0.0921%	$ 182,922	0.00000%	0.0000%	$ -	$ 182,922	$ 146,771	$ 36,151	$ -	$ -	$ 36,151
10442	Wasco Elec Coop	0.2075%	$ 412,309	0.00000%	0.0000%	$ -	$ 412,309	$ 333,148	$ 79,161	$ -	$ -	$ 79,161
11680	Weiser, City of	0.0778%	$ 154,513	0.00000%	0.0000%	$ -	$ 154,513	$ 88,736	$ 65,777	$ -	$ -	$ 65,777
10446	Wells Rural Electric Company	1.5674%	$ 3,114,509	0.00000%	0.0000%	$ -	$ 3,114,509	$ 2,498,072	$ 616,437	$ -	$ -	$ 616,437
10448	West Oregon Elec Coop	0.0000%	$ -	0.03042%	0.1344%	$ 78,123	$ 78,123	$ 64,014	$ 14,109	$ -	$ -	$ 14,109
10451	Whatcom County PUD #1	0.4168%	$ 828,172	0.00000%	0.0000%	$ -	$ 828,172	$ 663,866	$ 164,306	$ -	$ -	$ 164,306
10502	Yakama Power	0.0761%	$ 151,246	0.00000%	0.0000%	$ -	$ 151,246	$ -	$ 151,246	$ 121,387	$ 939	$ 152,185
	TOTAL	**100%**	**$ 198,703,417**	**22.6278%**	**100%**	**$ 58,111,585**	**$ 256,815,002**	**$ 170,906,083**	**$ 85,908,919**	**$ 34,293,922**	**$ 265,294**	**$ 86,174,213**