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 Wholesale Power Rate Case Initial Proposal

REVENUE REQUIREMENT STUDY

November 2005

WP-07-E-BPA-02

BONNEVILLE
POWER ADMINISTRATION

REVENUE REQUIREMENT STUDY

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COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFDUC	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
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
ASC	Average System Cost
Avista	Avista Corporation, Water Power Division
BASC	BPA Average System Cost
BiOp	Biological Opinion
BOR	Bureau of Reclamation
BPA	Bonneville Power Administration
BP EIS	Business Plan Environmental Impact Statement
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine

CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DMP	Data Management Procedures
DO	Debt Optimization
DOE	Department of Energy
DROD	Draft Record of Decision
DSIs	Direct Service Industrial Customers
DSR	Debt Service Reassignment
ECC	Energy Content Curve
EFB	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
Energy Services	Energy Services, Inc.
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBPF	Forward Flat-Block Price Forecast
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
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)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers

GTA	General Transfer Agreement
GWh	Gigawatthour
HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU REP Settlement benefits	Investor-Owned Utilities Residential Exchange Program Settlement benefits
IOUs	Investor-Owned Utilities of the Pacific Northwest
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISC	Investment Service Coverage
ISO	Independent System Operator
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
K/I	Kilowatt-hour/Investment Ratio for Low Density Discount
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
LRSCP	Lower Snake River Compensation Plan
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
M/M	Meters/Miles-of-Line Ratio for Low Density Discount
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
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)

MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NEW	Northwestern Energy
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
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PFR	Power Function Review

PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
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
RFA	Revenue Forecast Application
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
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
SCRA	Supplemental Contingency Reserve Adjustment
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
Slice	Slice of the System product
STREAM	Short-Term Risk Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge

TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
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
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. INTRODUCTION

1.1 Purpose and Development of the Revenue Requirement Study for Generation

The purpose of this Study is to establish the level of revenues from wholesale power rates 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. 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.

The cost evaluation period, as defined by the Federal Energy Regulatory Commission (FERC), is the period extending from the last year for which historical information is available, through the proposed rate test period. The cost evaluation period for this rate filing includes Fiscal Years (FY) 2005-2009. The Study is based on generation revenue requirements for the rate test period FY 2007-2009, including the results of generation repayment studies. This Study does ***not*** include revenue requirements or a cost recovery demonstration for the Bonneville Power Administration's (BPA) transmission function.

The Study outlines the policies, forecasts, assumptions, and calculations used to determine revenue requirements. Legal requirements are summarized in Chapter 5 of the Revenue Requirement Study, WP-07-E-BPA-02. Volumes 1 and 2 of Revenue Requirement Study Documentation, WP-07-E-BPA-02A and WP-07-E-BPA-02B, respectively, contain key technical assumptions and calculations, the results of the generation repayment studies, and a further explanation of the repayment program and its outputs.

Revenue requirements for this study were developed using a cost accounting analysis comprised of three parts. First, repayment studies for the generation function were prepared to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and related generation assets. Repayment studies are conducted for each year of the rate test period, and cover the 50-year repayment period. Second, generation operating expenses and minimum required net revenues are projected for each year of the rate test period. Third, annual Planned Net Revenues for Risk (PNRR) are determined taking into account risks, BPA's cost recovery goals, and other risk mitigation measures. From these three steps, revenue requirements are set at the revenue level necessary to fulfill cost recovery requirements and objectives. *See*, Figure 1, Generation Revenue Requirement Process, of this chapter.

Consistent with Department of Energy (DOE) policy RA 6120.2 and the standards applied by FERC on review of BPA's rates, the adequacy of both current and proposed rates must be demonstrated. BPA conducts a current revenue test to determine whether revenues projected from current rates can meet cost recovery requirements. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, current rates could be extended. The current revenue test, described in Chapter 4.2 of this document, demonstrates that revenues from current rates will not recover generation costs. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test and repayment period. The revised revenue test, contained in Chapter 4.3 of this document, demonstrates that revenues from the proposed wholesale power rates will recover generation costs in each year of the rate test period and over the ensuing 50-year repayment period. Rate test period costs are projected to be recovered with a very high confidence level meeting the 95 percent probability that all United States (U.S.) Treasury payments in the generation function will be recovered on time and in full through wholesale power rates over two years. Over the proposed three-year rate period, the standard is equivalent to 92.6 percent. *See*, Risk Analysis Study, Section 1.1, WP-07-E-BPA-04.

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed rates over the three-year rate period. These net revenues are set at the lowest level necessary to achieve BPA's cost recovery objectives, when combined with other risk mitigation tools in the face of large hydro condition uncertainty, fish and wildlife recovery cost uncertainty, market price volatility, and other risks.

Table 1

PROJECTED NET REVENUES FROM PROJECTED RATES
($000s)

Fiscal Year		Generation
2007	Projected Revenues From Proposed Rates	2,837,639
	Projected Expenses	2,590,056
	Net Revenues	247,583
2008	Projected Revenues From Proposed Rates	2,759,352
	Projected Expenses	2,539,323
	Net Revenues	220,029
2009	Projected Revenues From Proposed Rates	2,706,905
	Projected Expenses	2,642,749
	Net Revenues	64,156
Average 2007-2009	Projected Revenues From Proposed Rates	2,767,965
	Projected Expenses	2,590,709
	Net Revenues	177,256

Table 2 shows planned generation amortization payments to the U.S. Treasury during the rate test period.

Table 2

PLANNED AMORTIZATION PAYMENTS TO U.S. TREASURY
FY 2007 – 2009 GENERATION REPAYMENT STUDIES

($000s)

Fiscal Year	Annual Amortization
2007	$170,273
2008	$185,211[1]
2009	$176,447[2]
Total	$531,931

[1] Includes Irrigation Assistance payment of $2,950.
[2] Includes Irrigation Assistance payment of $6,590.

Table 3 shows the derivation of the planned amortization payments. The total planned amortization amounts were derived through a two-step repayment run process. The first step is done as though Energy Northwest advanced refundings in FY 2001 and FY 2002, which locked in refunding in FY 2007-2009, had not occurred and determines the base level of Federal amortization. The second step adds the advanced refundings amounts to the base amounts (fulfilling the commitment of paying a dollar of Federal amortization for every dollar of EN advanced refunding principal commitment). *See*, Homenick, *et al.*, WP-07-E-BPA-11.

Table 3

AMORTIZATION PAYMENTS DERIVATION

($000s)

Fiscal Year	Base Amortization (without Advanced Refunding)	Advanced Refunding Amount Added	Total Rate Period Amortization
2007	$113,173	$57,100	$170,273
2008	$121,711[1]	$63,500	$185,211
2009	$98,347[2]	$78,100	$176,447
Total	$333,231	$198,700	$531,931

[1] Includes Irrigation Assistance payment of $2,950.

[2] Includes Irrigation Assistance payment of $6,590.

FIGURE 1

GENERATION REVENUE REQUIREMENT PROCESS

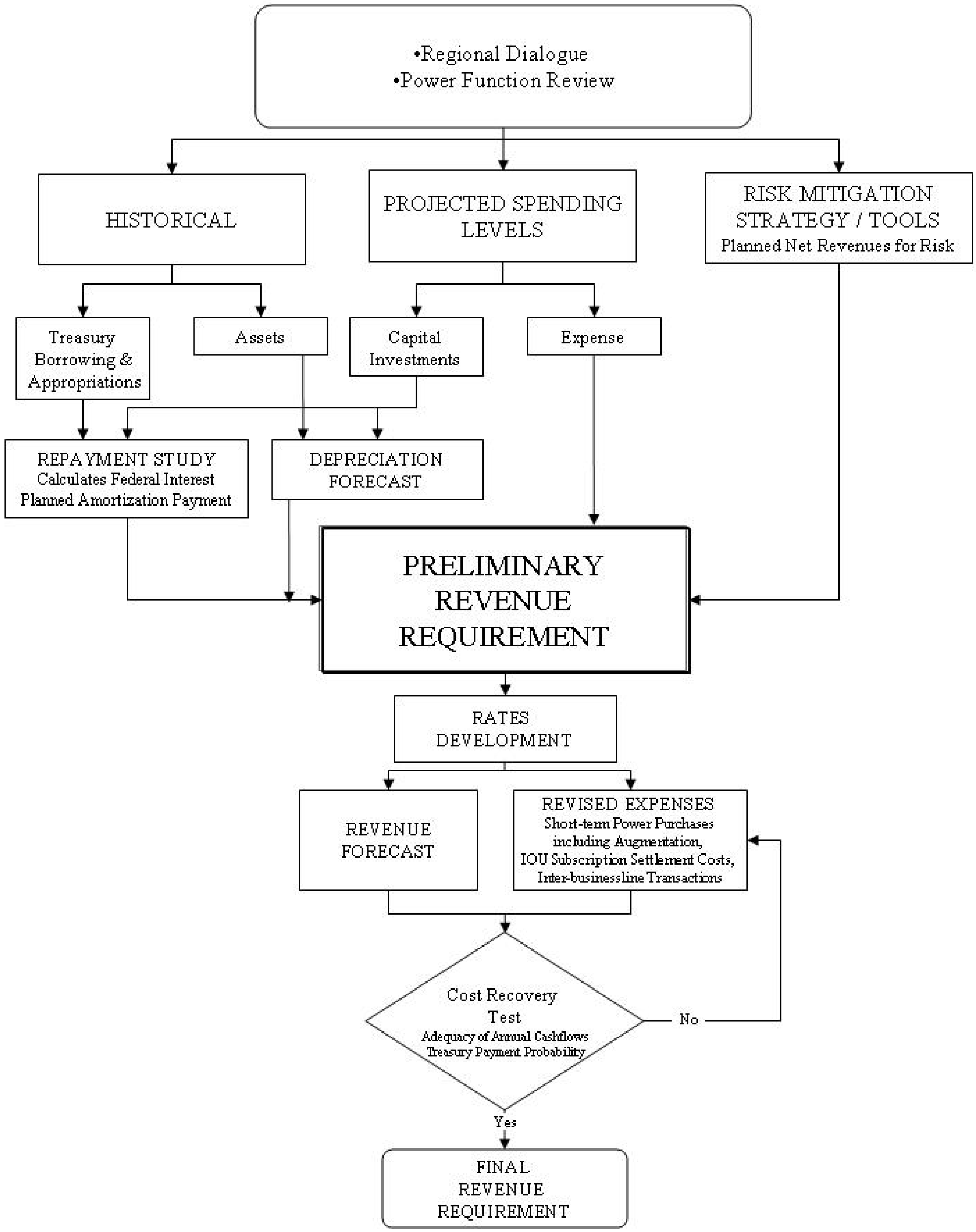
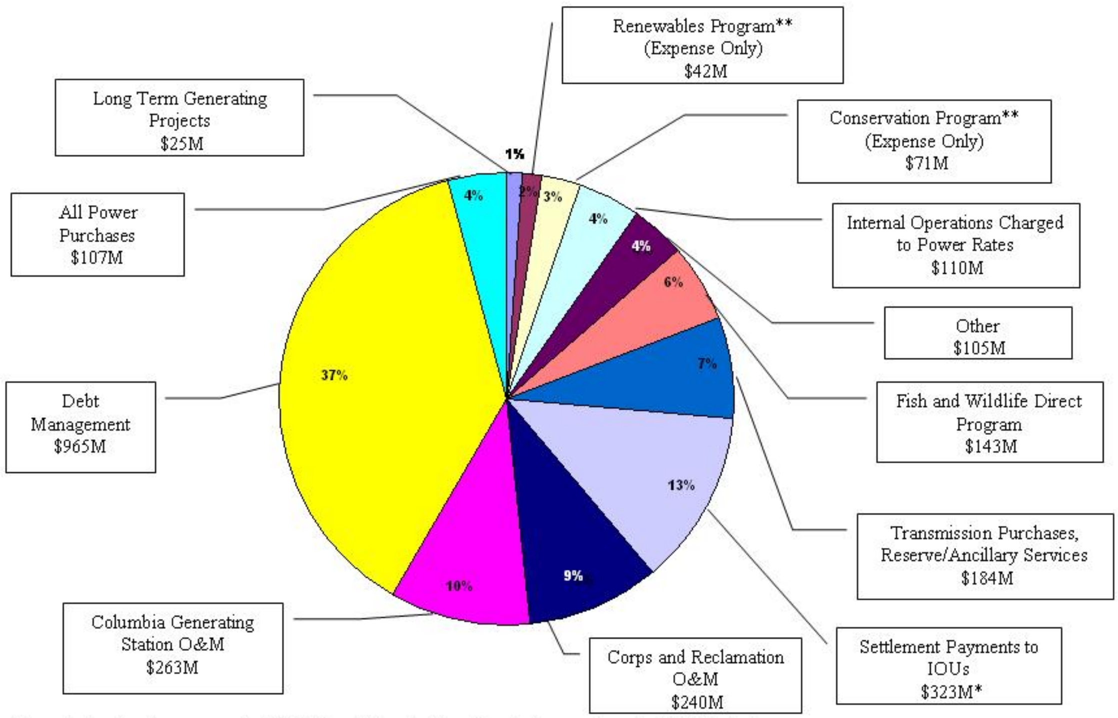


Figure 2

Composition of 2007-2009 Generation Expenses from Power Function Review



*Total includes calculated settlement costs for FY07-09 and deferral of benefits plus interest from the FY02-06 timeframe.

**Does not include revenues from aMWs sold.

1.2 Public Involvement Process

BPA participated in two major public processes that have had, and will continue to have, significant impacts on its methods and costs of doing business: the Regional Dialogue (RD) and the Power Function Review (PFR). In 2004, BPA began a two-phase public process, the Regional Dialogue, to outline how it will market Federal power and distribute the costs and benefits of the FCRPS. The first phase, the Near-Term Policy, focused on issues that needed to be addressed prior to the beginning of this rate case. The second phase is on-going and focuses on long-term issues that must be resolved prior to the end of current Subscription contracts in 2011.

The other major public process was the PFR which had the objective of ensuring that BPA's generation costs are as low as possible, consistent with sound business practices, thereby facilitating full cost recovery with power rates at or below market prices. Chapter 2 describes the chronology of the spending level development process. The PFR recommendations form the basis of these revenue requirements. *See*, Study, Figure 2 and Appendix A, WP-07-E-BPA-02.

These revenue requirements reflect both the recommendations of the Power Function Review and the applicable decisions made in the first phase of the Regional Dialogue process.

2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

2.1 Development Process for Spending Levels

The development of program levels reflected in BPA's revenue requirement began early in the FY 2002-2006 rate period. BPA began to impose more stringent cost controls and spending reductions in FY 2002 in response to the financial effects of the California energy crisis. It continued with the Financial Choices public process which ran from July to November 2002. This was an effort to engage customers and constituents in developing options for resolving an expected $860 revenue shortfall. BPA built on these efforts with the Power Net Revenue Improvement Sounding Board which met ten times from November 2003 to June 2004. The Sounding Board was made up of representatives from public utilities, IOUs, customer and constituent groups, NPCC, and tribes. Its primary purpose was to identify $100 million in cost reductions and revenue enhancements in fiscal years 2004 and 2005. Through this process, $111 million in revenue enhancements and cost reductions were identified. In addition to these public processes, BPA has met regularly with customer and constituent groups such as the Customer Collaborative to provide updates on the agency's financial condition to promote transparency.

The development of the specific program levels in this proposal occurred primarily in two forums, the RD process and the PFR.

2.2 Regional Dialogue

The RD process evolved out of an effort jointly-sponsored by BPA and the Northwest Power and Conservation Council (NPCC), initiated in 2002, to outline how BPA should market the power generated by the FCRPS. In 2004, BPA split the RD process into two phases. The first phase, known as the near-term Regional Dialogue, addressed issues needing immediate resolution for the FY 2007-2009 rate period. The second, on-going phase, known as the long-term Regional

Dialogue, focuses on long-term issues that need to be resolved before existing power contracts expire in 2011.

The first phase of the Regional Dialogue focused on issues ranging from the length of the first post-2006 rate period to how to best serve new public power customers. The RD process included numerous meetings with and comment from customers and constituents. It included decisions from a Conservation and Renewables Workgroup and from a public process on service to DSIs. On June 28, 2005, BPA issued its Final Post-2006 Conservation Program Structure report.[1] A separate Record of Decision was developed on service to DSIs. The near-term Regional Dialogue culminated in a Record of Decision (ROD) and a policy statement, known as the Near-Term ROD and the Near-Term Policy, issued in February 2005.[2]

Some of the conclusions of the Regional Dialogue had a direct focus on financial issues. The Regional Dialogue recommended that BPA should cap its net expense for facilitating renewable resource development at $21 million per year. It also recommended that BPA should provide service to Direct Service Industries (DSIs) at a known quantity and capped cost which would be determined in a separate DSI ROD.

To facilitate a decision on the benefits to be paid to DSIs, BPA had a separate, extended public process for this issue. BPA published a DSI ROD on June 30, 2005. In the DSI ROD, the Administrator determined that the DSI benefit should be capped at $59 million per year through 2011.[3]

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[1] See the BPA web site at www.bpa.gov/energy/n/post2006conservation for a discussion of the post-2006 conservation structure.
[2] See the BPA web site at www.bpa.gov/power/pl/RegionalDialogue/announcements.shtml for a copy of the near-term Regional Dialogue Record of Decision.
[3] See the BPA web site at www.bpa.gov/power/pl/RegionalDialogue/announcements.shtml for a copy of the Record of Decision

In the Near-Term ROD, BPA also said that it would continue to focus on promoting financial transparency, allow for public input on agency costs, and demonstrate management of those costs including engaging customers in the PFR to discuss power spending levels that will be used to set power rates for the FY 2007-2009 rate period.

2.3 Power Function Review

BPA began the PFR process in January 2005 with the first of a series of technical, management, and public workshops. The PFR was designed to provide an opportunity for customers and constituents to examine, understand, and provide input on BPA's cost projections that form the basis for the WP-07 wholesale power rate case. A total of 19 workshops were held between January and May of 2005. Nine of the workshops focused on technical discussions of BPA program areas. Five workshops were focused on policy issues with utility general managers as the intended audience. Workshops were also held in Portland, OR; Seattle, WA; Spokane, WA; Idaho Falls, ID; and Missoula, MT for general public discussion and comment. The PFR workshops focused on the projected capital investments and operations and maintenance costs of the major programs that affect wholesale power rates. The workshops examined the projected spending levels of the Columbia Generating Station, Corps of Engineers, Bureau of Reclamation, Conservation program, Renewables program, Fish and Wildlife program, Power Business Line internal operations, Transmission Purchases and Ancillary Services program, BPA corporate costs, risk mitigation, and Federal and non-Federal debt management. Where appropriate, the Near-Term policy decisions were incorporated in the PFR spending level projections.

There were separate public workshops held on the Fish and Wildlife program in addition to and concurrent with the PFR. Five workshops were held around the region from January through March 2005 to discuss in detail the projected Fish and Wildlife Program expense and capital spending for the FY 2007-2009 rate period. Additionally, BPA participated in numerous meetings with the Northwest Power and Conservation Council (NPCC), States, Tribes, constituents and customers beginning in 2004 to get input on the appropriate approach to the Program spending, discussion of a potential Program-level Memorandum of Agreement (MOA) for FY 2007 - 2009, and the appropriate level of funding. The comments gathered in these forums were used to inform forecast of FY 2007-2009 spending levels incorporated in the PFR.

Based on comments received during the PFR process, BPA changed some of its forecasted program costs. The final PFR report, which is included in Appendix A of this document, reflects an average annual expense reduction of $96 million from $2,674 million. The close-out report included average annual expenses of $2,577 million with capital investments averaging $206 million per year. *See*, Study, Appendix A, WP-07-E-BPA-02. The changes made during the PFR include, among other things, an $8 million annual decrease due to expected efficiencies for Internal Operations charged to power, a $4 million annual increase in the Fish and Wildlife Direct Program expense, a $4 million annual decrease in transmission acquisition expenses due to a revised GTA wheeling forecast, and a $22 million annual decrease in CGS operations and maintenance costs. In addition to changes in spending levels, BPA committed to conducting an additional public process to review program spending levels that will be concurrent with this rate proceeding so that any reductions in spending levels can be incorporated in the final proposal.

BPA's debt management was explained and discussed during the PFR because BPA believed it important that participants understand the effects and implications of debt management decisions. However, it was BPA's capital investment assumptions for this rate proposal that were decided in this process. Debt management decisions were not made in the PFR nor are they part of the issues debated in this rate proceeding.

Subsequent to the close-out of the PFR, BPA has updated the following projected expenses for FY 2007-2009 and re-characterized others. The decision on the level of DSI benefits was made after the PFR and resulted in an increase of $19 million per year over the PFR close-out report. The forecast value of short-term power purchases was replaced with a more recent estimate. The Residential Exchange Settlement costs were re-characterized to recognize the different components. Of the PFR total of $323 million, $23 million per year is now recognized as Contracted Power Purchases because it is associated with a deferred augmentation expense while $1 million was added to the remainder as interest on a deferred expense that inadvertently had not been included in the PFR forecast. Depreciation, amortization, and debt service costs have been updated to reflect investment decisions outlined in the PFR close-out report. These changes are reflected in this study.

2.4 Capital Funding

FCRPS capital investments include COE, Reclamation, and BPA capital investments and third-party resource investments for which debt is secured by BPA (capitalized contracts). Current FCRPS capital outlay projections are $875 million for the FY 2007-2009 rate period and $1,441 million for the FY 2005-2009 cost evaluation period. These investments include:

- efficiency and reliability improvements and replacements in hydro generation;

- investment in fish and wildlife recovery funded by BPA and by appropriations and implemented by various groups in the Northwest, including the COE and Reclamation. Fish and wildlife investment includes tributary passage, hatchery facility construction, gas abatement, mainstem passage, and land acquisition provided such costs exceed $1 million and such investment provides a creditable/quantifiable benefit against a defined obligation for BPA;

- investment in capital equipment;

- investment in conservation activities; and

- capital investments at Energy Northwest's Columbia Generating Station.

The sources of capital for FY 2007-2009 investments are summarized below. A more detailed breakout can be found in Table 4.

Investments in fish and wildlife recovery	($ in millions)
Bonds Issued to U.S. Treasury	108
Federal Appropriations	218
Total	326

Investments in revenue producing assets and other non-fish and wildlife investments	
Bonds Issued to U.S. Treasury	415
Federal Appropriations	0
Non-Federal	46
Total	461

This Study does not project that any capital investments will be funded from current revenues.

2.4.1 Bonds Issued to the U.S. Treasury

This source of capital will be used to finance FY 2007-2009 BPA capital program investments and COE and Reclamation investments that BPA has agreed to direct-fund under P.L. No. 102-486. These expenditures include a projected $523 million, split between BPA Fish and Wildlife Direct Program investments ($108 million) and generating resource investments of the COE and Reclamation ($415 million) during FY 2007–2009.

Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in Chapter 6 of the Documentation, WP-07-E-BPA-02A.

2.4.2 Federal Appropriations

This Study reflects that all COE and Reclamation capital investments of the FCRPS will be financed by Federal appropriations unless they are direct-funded by BPA. Such appropriated investments are projected to total $217.7 million in COE investments for fish and wildlife recovery during the rate period. No other appropriations-financed investments are forecast for the rate period. Capital investments funded by this source do not become BPA's obligation until placed in service.

The interest rate forecast for appropriated capital investments expected to be placed in service is found in Chapter 6 of Revenue Requirement Study Documentation, WP-07-E-BPA-02A. Each new capital investment is assigned a rate from the U.S. Treasury yield curve prevailing in the month prior to the beginning of the FY in which the new investment is placed in service.

To determine interest during construction for new capital investments, the prevailing U.S. Treasury one-year rate for each FY of construction, is applied to the sum of: (1) the cumulative expenditures made; and (2) interest during construction that has accrued prior to the end of the subject FY. *See,* Study, Chapter 5, WP-07-E-BPA-02 and Revenue Requirement Study Documentation, Chapter 9, WP-96-FS-BPA-02A.

2.4.3 Third-Party Debt

Third-party debt differs from U.S. Treasury debt, in that entities other than BPA or U.S. Treasury issue the debt. BPA's promise to make payments serves as security for bonds or other debt that the third-party issues, resulting in wider market access and potentially more favorable interest rates for the seller. Examples of acquisitions financed in this way include Energy Northwest's WNP-1, –3 and Columbia Generating Station (CGS) nuclear power projects, and the Lewis County Public Utility District Hydroelectric (Cowlitz Falls). This Study includes debt service on $46 million in projected CGS capital investments by Energy Northwest to be financed by issuing bonds during the rate period. Each new capital investment is assigned an interest rate from the tax exempt municipal bond yield curve corresponding with the term of the bond. *See,* Documentation, Chapter 6, WP-07-E-BPA-02.

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TABLE 4

FEDERAL COLUMBIA RIVER POWER SYSTEM (FCRPS)
PROJECTED CAPITAL FUNDING REQUIREMENTS FOR THE POWER BUSINESS LINE
2007 RATE PROPOSAL
(Annual Outlays in Millions of Dollars)

	Actual	Current Rate Period						Next Rate Period			
	Average FYs '97-'01	Actual FY 2002	Actual FY 2003	Actual FY 2004	Est. FY 2005	Est. FY 2006	Average FYs '02-'06	FY 2007	FY 2008	FY 2009	Average FYs '07-'09
POWER											
Capital Requirements for Revenue Producing Investments											
Corps & Bureau Additions/Replacements - Direct Funded	33.7	50.0	120.0	115.0	126.1	131.0	108.4	133.0	145.0	137.0	138.3
Corps & Bureau Additions/Replacements - Appropriations[1]	40.8	4.4	1.4	16.2	0.0	0.0	4.4	0.0	0.0	0.0	0.0
PBL Capital Equipment	4.9	2.0	45.1	13.4	19.2	13.4	18.6	12.1	13.9	12.3	12.8
Capitalized Bond Premium	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CGS: Additions/Replacements[2,3]	12.4	0.0	41.3	26.6	0.0	31.0	19.8	12.1	25.6	8.7	15.5
CGS: Fuel[4]	0.0	0.0	0.0	0.0	93.4	0.0	18.7	0.0	0.0	0.0	0.0
Other Non - Federal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Capital Requirements for Revenue Producing Investments	**93.3**	**56.4**	**207.8**	**171.2**	**238.7**	**175.4**	**169.9**	**157.2**	**184.5**	**158.0**	**166.6**
Cumulative Capital Requirements for Rev Producing Investments		**56.4**	**264.2**	**435.5**	**674.2**	**849.5**		**157.2**	**341.7**	**499.7**	
Capital Requirements for Non-Revenue Producing and Public Benefit Investments											
Energy Conservation	16.2	40.0	0.0	30.0	22.5	44.0	27.3	32.0	32.5	32.5	32.3
Fish Investment											
BPA Fish and Wildlife Investment[5]	18.0	0.0	20.0	0.0	10.0	36.0	13.2	36.0	36.0	36.0	36.0
Corps & Bureau Fish Investment - Appropriations[5]	8.2	9	68	60.6	134.2	22.2	58.8	76.1	135.8	5.8	72.6
Total Fish Investment	26.2	9	88	60.6	144.2	58.2	72.0	112.1	171.8	41.8	108.6
Other Third - Party	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Annual Capital Req. for Non-Rev. & Public Benefit Invests.	**42.4**	**48.8**	**88.4**	**90.6**	**166.7**	**102.2**	**99.3**	**144.1**	**204.3**	**74.3**	**140.9**
Cumulative Capital Req. for Non-Rev. & Public Benefit Invest.		**48.8**	**137.2**	**227.8**	**394.5**	**496.7**		**144.1**	**348.4**	**422.7**	
ANNUAL FUNDING REQUIREMENTS FOR POWER	**135.7**	**105.2**	**296.2**	**261.8**	**405.4**	**277.5**	**269.2**	**301.3**	**388.8**	**232.3**	**307.5**
CUMULATIVE FUNDING REQUIREMENTS FOR POWER	**0.0**	**105.2**	**401.4**	**663.3**	**1,068.7**	**1,346.2**		**301.3**	**690.1**	**922.4**	

FOOTNOTES:
[1] Reflects plant in service, including IDC, not expenditures.
[2] CGS new capital requirements were revenue-financed prior to FY 2002. For FY 2002-2006 these costs are debt-financed. The bond amount is shown for each year.
[3] FY 2003 includes the amount of capital for which bonds were issued for the Independent Spent Fuel Storage Installation Facility (ISFSI) project and other capital additions for Energy Northwest FY 2002, FY 2003, and FY 2004;
FY 2004 includes the amount of capital for which bonds were issued for Energy Northwest FY 2005 capital additions;
FY 2006 includes the following amounts of capital for which bonds will be issued: $4.9M for Energy Northwest FY 2006 and $26.1M for Energy Northwest FY 2007;
FY 2007 includes the amount of capital for which bonds will be issued for Energy Northwest FY 2008.
FY 2008 includes the amount of capital for which bonds will be issued for Energy Northwest FY 2009;
FY 2009 includes the amount of capital for which bonds will be issued for Energy Northwest FY 2010.
[4] FY 2005 includes $93.4M for Energy Northwest fuel purchases covering several years.
[5] Reflects annual average of the plant-in-service in all 13 scenarios used in 2002-2006 rate proposal.

3. DEVELOPMENT OF REVENUE REQUIREMENTS

Repayment studies are performed as the first step in determining revenue requirements. The studies establish the schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments.

The horizon of each repayment study is 50 years after each rate test year. The Revenue Requirement Study includes the results of generation repayment studies for each of the three years in the rate test period, FY 2007–2009. In conducting the repayment studies, BPA includes debt service payments associated with its capitalized contract obligations; fixed payments associated with long-term energy resource acquisition contracts; and outstanding and projected generation repayment obligations on appropriations and on bonds issued to U.S. Treasury.

Funding for replacements projected during the repayment period are also included in the repayment study, consistent with the requirements of RA 6120.2. COE and Reclamation replacements funded by appropriations and placed in service in 1994 or later have repayment periods that are set at the weighted average service life of all replacements going into service at that project in that year. Appropriations are scheduled to be repaid within the expected useful life of the associated facility, or 50 years, whichever is less.

Bonds issued by BPA to the U.S. Treasury may include 3- to 45-year terms, taking into account the estimated average service lives for investments and prudent financing and cash management factors. Some bonds are issued with a provision that allows the bond to be called after a certain time, typically five years. Bonds may also be issued with no early call provision. Early retirement of eligible bonds requires that BPA pay a bond premium to the U.S. Treasury. In addition, the interest rate that BPA pays on callable bonds is higher than the interest rate on non-callable bonds issued at the same time.

Bonds are issued to finance BPA conservation, fish and wildlife programs, and COE and Reclamation investments direct-funded by BPA, and are repaid within the terms and conditions of each bond issued to the U.S. Treasury. Bonds to finance fish and wildlife capital investments are issued with maturities not to exceed fifteen years, the same period over which BPA amortizes these capital investments. COE and Reclamation direct-funding bonds are issued with maturities not to exceed forty-five years. Conservation bonds are issued with maturities that are consistent with the period over which BPA amortizes these capital investments. Currently, BPA has three amortization schedules for conservation assets. Investments made prior to 2002, referred to as the Conservation Legacy program, use a straight-line, twenty year amortization period. Investments made from 2002 through 2006, known as Conservation Augmentation investments, have a declining ten year amortization period to be completed by 2011. Investments made beginning in 2007, known as Conservation Acquisition investments, will use a straight-line five year amortization period. *See,* Leathley *et al.*, WP-07-E-BPA-08.

Based on these parameters, the repayment study establishes a schedule of planned amortization payments and resulting interest expense by determining the lowest levelized debt service stream necessary to repay all generation obligations within the required repayment period.

Further discussion of the repayment program and tables is included in Appendix B of the Revenue Requirement Study, WP-07-E-BPA-02; and in Chapter 11 of Documentation, WP-07-E-BPA-02B. *See*, Study, Chapter 5, WP-07-E-BPA-02 for an explanation of repayment policies and requirements.

4. FY 2005 GENERATION REVENUE REQUIREMENTS

4.1 Revenue Requirement Format

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 Income Statement (Table 5A) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 16), Net Interest Expense (Line 25), Minimum Required Net Revenues (Line 27), and PNRR (Line 28). The sum of these four major components is the Total Revenue Requirement (Line 30).

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 27) result from an analysis of the Statement of Cash-Flow (Table 5B). 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 8), driven by the Non-Cash items shown in Lines 4, 5, 6, and 7 must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 14) and Cash from Treasury Borrowing and Appropriations (Line 21). 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 22). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) is then incorporated in the Income Statement (Line 27).

4.1.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 5A). Volume 1 of Revenue Requirement Study Documentation, WP-07-E-BPA-02A provides additional information on the development and use of the data contained in the tables.

Power System Generation Resources (Line 2). This category encompasses the costs associated with FCRPS power generated by Federal hydroelectric facilities operated by the COE and BOR and power obtained through contracts for non-Federal resources. This category includes lines 3 through 8, described below.

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Operating Generation Resources (Line 3). This category includes the operations and maintenance expenses associated with power-producing resources including the Columbia Generating Station, BOR, COE, and the annual expenses associated with long-term contract generating projects.

Operating Generation Settlement Payments (Line 4). A settlement agreement between the Confederated Tribes of the Colville Reservation and the United States was signed in 2004 concerning the construction of Grand Coulee Dam. The Settlement Act (Public Law 103-436) ratifying the settlement agreement, authorizes BPA to make annual payments to the Tribes for the use of tribal lands for power production at the Columbia Basin project.

Non-Operating Generation (Line 5). This category includes the decommissioning costs of the Trojan nuclear plant and the unfinished WNP-1 and WNP-3 nuclear plants.

Contracted Power Purchases (Line 6). This category includes augmentation power purchases, short-term (balancing) power purchases, hedging/mitigation, and the PNCA headwater benefit. Augmentation power purchase costs reflect the energy that BPA purchases in order to satisfy its obligation to meet the load requirements for public utilities. The PNCA headwater benefit refers to the costs associated with benefits BPA receives from storage projects in Canada.

Residential Exchange/IOU Settlement Benefits (Line 7). This category represents the benefits calculated under the settlement agreements with IOUs related to the Residential Exchange Program.

Renewable and Conservation Generation (Line 8). This category reflects the operating expenses of several generating projects fueled by renewable energy resources such as wind, geothermal, methane gas, solar, and “fish-friendly small hydro projects.” It also includes the cost of conservation programs including Marketing Development which are reimbursable contracts with equal and offsetting revenues, Market Transformation, Legacy Conservation programs, Technology Leadership, and Low Income Weatherization.

Transmission Acquisition and Ancillary Services (Line 9). This category includes the annual expenses associated with PBL’s Transmission Acquisition program. It represents costs associated with services necessary to deliver energy from resources to markets and loads. This includes transmission, ancillary services and real power losses, as purchased from the

Transmission Business Line (TBL) or non-Federal entities, TBL costs for generation integration of COE and Reclamation projects and metering and communication requirements.

Power Non-Generation Operations (Line 10). This category reflects the Power Business Line's internal costs associated with supporting the power function. It includes the costs of activities such as generation oversight, weather and stream flow forecasting, system operations planning, schedule planning, pre-scheduling, after-the-fact accounting of power transactions, power billing, customer account executives and customer service support staff, development and administration of power sales contracts, PBL strategy development, PBL financial reporting, analysis and budgeting, risk management and PBL human resources management.

F&W/Environmental Requirements (Line 11). BPA funds projects designed to accomplish measures in the NPCC's Columbia River Basin Fish and Wildlife Program and the NOAA Fisheries Biological Opinions (BiOP). 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 BiOP issued by the NMFS and the USFWS.

General and Administrative (Line 12). This category represents the allocated portion of BPA's Corporate General and Administrative costs, which are allocated to the business lines. Major functions besides the Executive Office are Corporate Communication, Finance, Diversity, and Safety.

This category also includes Shared Services and the Civil Service Retirement System (CSRS) expense. Shared Services represents the costs for information technology services, infrastructure and maintenance, building rent, maintenance and security, mail services, personnel services, library and printing services, internal training, purchasing, and furniture. CSRS reflects the costs for the unfunded liability of the Civil Service Retirement and Disability Fund, the Employees Health Benefit Fund and the Employees Life Insurance Fund.

Other Income, Expenses, and Adjustments (Line 13). This category consists of the capped DSI benefit as reflected in the DSI ROD dated June 30, 2005.

Non-Federal Debt Service (Line 14). This category consists of third-party debt service or payment costs associated with capitalized contracts and other long-term, fixed contractual obligations. Debt service costs associated with Energy Northwest projects (WNP-1, Columbia Generating Station, and WNP-3) make up the majority of these costs.

Depreciation and Amortization (Line 15). Depreciation is the annual capital recovery expense associated with FCRPS plant-in-service. Amortization is the annual capital recovery expense associated with non-revenue producing assets. Reclamation and COE (including Lower Snake River Fish and Wildlife Compensation Plan (LSRCP) plant, including assets for fish and wildlife recovery, is depreciated by the straight line method of calculation, using the composite service life of all projects, seventy-five years. Capital equipment (office furniture and fixtures and data processing hardware and software) is also depreciated by the straight line method using the average service lives for the particular categories of capital investment. Conservation investments are amortized over three different periods. Legacy conservation investments prior to the FY 2002-2006 rate period are amortized using a straight-line, twenty-year life. Conservation Augmentation investments in the FY 2002-2006 period are amortized using a declining life method with all amortization being complete in FY 2011. Conservation Acquisition investments beginning in FY 2007 are amortized using a straight-line, five-year life. *See*, Documentation, Chapters 3 and 4, WP-07-E-BPA-02A.

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

Interest on Appropriated Funds (Line 19). Interest on Appropriated Funds includes interest on COE and Reclamation appropriations as calculated in the generation repayment studies. *See*, Documentation, Chapters 4 and 6, WP-07-E-BPA-02A.

Interest on Bonds Issued to U.S. Treasury (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 State. 2776). Such interest expense is calculated in the generation repayment studies. Any payments of call premiums for bonds projected to be amortized are included in this line. *See*, Documentation, Chapters 4 and 6, WP-07-E-BPA-02A.

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 Business Line that carries over into the next year. 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 FY. Interest income is credited against bond interest. *See*, Documentation, Chapter 6, WP-07-E-BPA-02A.

Amortization of Capitalized Bond Premiums (Line 22). When a bond issued to the U.S. Treasury is refinanced, any call premium resulting from early retirement of the original bond is capitalized and included in the principal of the new bond. The capitalized call premium is then amortized over the term of the new bond. The annual amortization is a non-cash component of interest expense.

Capitalization Adjustment (Line 23). 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.

Allowance for Funds Used During Construction (AFUDC) (Line 24). 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.

Net Interest Expense (Line 25). Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 19), Interest on Bonds Issued to U.S. Treasury (Line 20), Interest

Credit on Cash Reserves (Line 21), Amortization of Capitalized Bond Premiums (Line 22), Capitalization Adjustment (Line 23), and AFUDC (Line 24).

Total Expense (Line 26). Total Expenses are the sum of Total Operating Expenses (Line 16) and Net Interest Expense (Line 25).

Minimum Required Net Revenues (Line 27). Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 5B), may be necessary to cover cash requirements in excess of accrued expenses. An explanation of the method used for determining the Minimum Required Net Revenues is included in Section 4.1.2 of this chapter.

Planned Net Revenues for Risk (PNRR) (Line 28). PNRR are the amount of net revenues to be included in rates for financial risk mitigation. PNRR, 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 2007-2009.

Total Planned Net Revenues (Line 29). Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 27) and PNRR (Line 28).

Total Revenue Requirement (Line 30). Total Revenue Requirement is the sum of Total Expenses (Line 26) and Total Planned Net Revenues (Line 28).

4.1.2 Statement of Cash Flows

Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 5B). Volumes 1 and 2 of Documentation, WP-07-E-BPA-02A and WP-07-E-BPA-02B, provide additional information related to the use and development of the data contained in the 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 operating activities will be sufficient to cover the planned amortization and irrigation assistance payments (the difference between Lines 8 and 21) without causing the Annual Increase (Decrease) in Cash (Line 22) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 27).

Depreciation and Amortization (Line 4). Depreciation is from the Income Statement (Table 5A, Line 15). It is included in computing Cash Provided By Operating Activities (Line 8) because it is a non-cash expense of the FCRPS.

Amortization of Capitalized Bond Premiums (Line 5). Amortization of capitalized bond premiums is from the Income Statement (Table 5A, line 22). It is included in computing Cash Provided By Operating Activities (Line 8) because it is a non-cash expense of the FCRPS.

Capitalization Adjustment (Line 6). Capitalization Adjustment is from the Income Statement (Table 5A, Line 23). It is a non-cash contra expense.

Accrual Revenues (Line 7). Accrual revenues are primarily associated with settlement agreements reached in prior periods. The annual accrual revenues, which are part of the total revenues recovering the FCRPS revenue requirement, are included here as a non-cash adjustment to cash from current operations.

Cash Provided By Operating Activities (Line 8). Cash Provided By Current Operations, the sum of Lines 2, 4, 5, 6, and 7, is available for the year to satisfy cash requirements.

Investment in Utility Plant (Line 11). Investment in Utility Plant represents the annual increase in additions to appropriated plant-in-service and to capital expenditures for COE, Reclamation, and BPA construction work-in-progress funded by bonds. *See,* Documentation, Chapter 4, WP-07-E-BPA-02A.

Investment in Conservation (Line 12). Investment in Conservation represents the annual increase in capital expenditures associated with Conservation programs. *See*, Documentation, WP-07-E-BPA-02A, Chapter 4.

Investment in Fish and Wildlife (Line 13). 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 the BiOP issued by NOAA Fisheries and USFWS.

Cash Used for Investment Activities (Line 14). Cash Used for Investment Activities is the sum of Lines 11, 12, and 13.

Increase in Bonds Issued to U.S. Treasury (Line 16). This category 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. *See*, Documentation, Chapter 7, WP-07-E-BPA-02A.

Repayment of Bonds Issued to U.S. Treasury (Line 17). This is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury as determined in the generation repayment studies. *See*, Documentation, Chapter 6, WP-07-E-BPA-02B.

Increase in Federal Construction Appropriations (Line 18). Increase in Congressional Capital Appropriations represents congressional appropriations projected to be received during the year for COE and Reclamation capital projects. *See*, Documentation, Chapter 4, WP-07-E-BPA-02A.

Repayment of Federal Construction Appropriations (Line 19). Repayment of Capital Appropriations represents projected amortization of outstanding COE and Reclamation appropriations as determined in the generation repayment studies. *See*, Documentation, Chapter 6, WP-07-E-BPA-02B.

Payment of Irrigation Assistance (Line 20). 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*, Documentation, Chapter 9, WP-07-E-BPA-02A.

Cash Provided by Borrowing and Appropriations (Line 21). Cash Provided by Borrowing and Appropriations is the sum of Lines 16 through 20. 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 22). 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.

Planned Net Revenues for Risk (PNRR) (Line 23). PNRR reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 5A, Line 28).

Total Annual Increase (Decrease) in Cash (Line 24). Total Annual Increase (Decrease) in Cash in the sum of Lines 22 and 23. It is the total annual cash that is projected to be available to add to BPA's cash reserves.

4.2 Current Revenue Test

Consistent with RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test determines whether the revenues expected from current rates can continue to meet cost recovery requirements and, therefore, be extended. *See*, Tables 6 and 7 at 51-53.

4.3 Revised Revenue Test

Consistent with RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements as well as BPA's TPP standard for the rate period. The revised revenue test was conducted using the base case forecast of revenues under proposed rates. The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery requirements and meet risk mitigation policy for the rate period of FY 2007 through 2009.

For the rate test period, the demonstration of the adequacy of proposed rates is shown on Tables 8A (Income Statement) and 8B (Cash-Flow Statement). *See*, Tables 8A and 8B, 55-56. Table 8B, Statements of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 8A (Line 28) for making the planned annual amortization and irrigation assistance payments and achieving the Administrator's financial objectives. This is demonstrated by the Annual Increase (Decrease) in Cash (Line 22). The annual cash-flow (Line 22) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash requirements.

4.4 Repayment Test at Proposed Rates

Table 9 demonstrates whether projected revenues from proposed rates are adequate to meet the cost recovery criteria of RA 6120.2 over the repayment period. The data are presented in a format consistent with the revised revenue tests (Tables 8A and 8B) and separate accounting analyses. The focal point of these tables is the Net Position (Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each of the years of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the allowable time. As shown in Column K, the resulting Net Position is greater than zero for each year of the rate approval period and in each year of the repayment period. The historical data on this table have been taken from BPA's separate accounting analysis. The rate test period data have been developed specifically for this rate filing. The repayment period data are presented consistent with the requirements of RA 6120.2.

5. REVENUE REQUIREMENT LEGAL REQUIREMENTS AND POLICIES

This chapter summarizes:

- the statutory framework that guides the development of BPA's revenue requirements and the allocation of FCRPS costs among the various users of the system; and

- the repayment policies that BPA follows in the development of its revenue requirement.

5.1 Development of BPA's Revenue Requirements

BPA's revenue requirements are governed by four main legislative acts: The Bonneville Project Act of 1937, P.L. No. 75-329, 50 Stat. 731; the Flood Control Act of 1944, P.L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River Transmission System Act (Transmission System Act) of 1974, P.L. No. 93-454, 88 Stat. 1376; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), P.L. No. 96-501, 94 Stat. 2697. Other statutory provisions that guide the development of BPA's revenue requirements include the Federal Power Act, as amended by the Energy Policy Act of 1992 (EPA-92), P.L. No. 102-486, 106 Stat. 2776; the Colville Settlement Act, P.L. No. 103-436, 108 Stat. 4577; and the Omnibus Consolidated Recissions and Appropriations Act of 1996, P.L. No. 104-134, 110 Stat. 132. DOE Order "Power Marketing Administration Financial Reporting," RA 6120.2, issued by the Secretary of Energy provides guidance to Federal power marketing agencies regarding repayment of the Federal investment.

5.1.1 Legal Requirements Governing the FCRPS Revenue Requirement

BPA's rates must be set in a manner that ensures revenue levels sufficient to fully recover its costs. This requirement was first set forth in Section 7 of the Bonneville Project Act, 16 U.S.C. §832f (amended 1977):

> Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of Bonneville project) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years . . .

Development of the FCRPS revenue requirements is a critical component of meeting this ratemaking directive. Section 9 of the Transmission System Act, 16 U.S.C, §838g, also strongly reflects this cost recovery principle, providing that rates be set:

> [A]t levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to this Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.

Similar guidelines are provided in Section 7 of the Northwest Power Act, 16 U.S.C. §839e. Section 7(a)(1), 16 U.S.C. §839e(a)(1), provides:

> The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this [Act] and other provisions of law. Such rates shall be established in accordance with Sections 9 and 10 of the Federal Columbia River Transmission System Act (16 U.S.C. §838), Section 5 of the Flood Control Act of 1944, and the provisions of this of this [Act].

Section 7(n) of the Northwest Power Act provides additional guidance regarding cost recovery for the FY 2007-2009 rate period, and preserves BPA's ability to establish appropriate reserves subsequent to FY 2006:

> Notwithstanding any other provision of this section, rates established by the Administrator, under this section shall recover costs for protection, mitigation and enhancement of fish and wildlife, whether under the Pacific Northwest Electric Power Planning and Conservation Act or any other Act, not to exceed such amounts the Administrator forecasts will be expended during the fiscal year 2002-2006 rate period, while preserving the Administrator's ability to establish appropriate reserves and maintain a high Treasury payment probability for the subsequent rate period.

16 U.S.C. § 839e(n).

The Northwest Power Act also makes it clear that a primary purpose of confirmation of BPA rates by FERC is to assure that the revenue requirement is adequate to assure timely U.S. Treasury repayment. Section 7(a)(2), 16 U.S.C. §839e(a)(2), provides:

> Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6) of this section, upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates:
>
> (A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs,
>
> (B) are based upon the Administrator's total system costs, and
>
> (C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.

In addition to reiterating and clarifying the cost recovery principle, the Northwest Power Act provided supplementary authority to sell bonds to the U.S. Treasury to finance BPA's new conservation and renewable resource programs. *See,* 16 U.S.C. §838i. More recently, the EPA-92 clarified BPA's authority to provide funds directly to the COE and Reclamation for hydroelectric generation additions, improvements, and replacements, as well as O&M expenses. *See,* P.L. No. 102-486, 1992 U.S. Code Cong. & Admin. News, 106 Stat. 2776. Other provisions that have particular relevance to the repayment of power costs can be found in the Reclamation Project Act of 1939 (codified as amended in scattered sections of 43 U.S.C.); the Grand Coulee Dam - Third Powerplant Act of June 14, 1966, P.L. No. 89-448, 80 Stat. 200, authorizing construction of the Grand Coulee Dam Third Powerhouse; and P.L. No. 89-561, 80 Stat. 707, Act of September 7, 1966, which partially amended P. L. No. 89-448. The costs associated with these projects and programs, as well as the other costs incurred by the Administrator in furtherance of BPA's mission, are included in the Revenue Requirement Study, WP-07-E-BPA-02.

5.1.2 Colville Settlement Act Credits

The Confederated Tribes of the Colville Reservation Grand Coulee Dam Settlement Act approves and ratifies the Settlement Agreement entered into by the United States and the Confederated Tribes of the Colville Reservation (Colville Tribes) related to the claims for a portion of the revenues from Grand Coulee Dam, and directs BPA to carry out its obligations under the settlement agreement. *See*, P. L. No. 103-436, Nov. 2, 1994, 108 Stat. 4577.

The Settlement Agreement obligates BPA to make annual payments to the Colville Tribes. Payments have been tied to both BPA's average prices and the amount of annual generation from Grand Coulee Dam. Under the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-13, 110 Stat. 1321, BPA receives annual credits from the U.S. Treasury against payments due the U.S. Treasury, in order to defray a portion of the costs of making payments to the Colville Tribes. Revenues credited to BPA associated with the Settlement Agreement are $17 million in FY 1999, $18 million in FY 2000, and $18 million in FY 2001. The credits for the 2007-2009 rate period are forecast to be $4.6 million in each FY.

5.1.3 The BPA Appropriations Refinancing Act

As in the prior rate period, BPA's power rates for the FY 2007-2009 rate period will reflect the requirements of the Refinancing Act, part of the Omnibus Consolidated Recissions and Appropriations Act of 1996, 16 U.S.C. §838l, P.L. No. 104-134, 110 Stat. 1321, enacted in April 1996. The Refinancing Act required that unpaid principal on FCRPS appropriations (old capital investments) at the end of FY 1996 be reset at the present value of the principal and annual interest payments BPA would make to the U.S. Treasury for these obligations absent the Refinancing Act, plus $100 million. *Id*. at §838l(b)(I). The Refinancing Act also specifies that the new principal amounts of the old capital investments be assigned new interest rates from the U.S. Treasury yield curve prevailing at the time of the refinancing transaction. *Id*. at §838l(a)(6)(A).

The Refinancing Act specifies that repayment periods on new principal amounts may not be earlier than determined prior to the refinancing. *Id*. at §838l(d).

The Refinancing Act specifies that the prevailing U.S. Treasury yield curve will be used to calculate interest during construction (IDC) and to assign interest rates to new capital investments funded by appropriations. *See*,16 U.S.C. §838l(f). New capital investments are defined as capital investments funded by appropriations for a project placed in service after September 30, 1996. *Id*. at §838l(a)(3). The IDC in each FY of construction for new capital investments is the prevailing one-year U.S. Treasury rate. *Id*. at §838l(f)(1). The IDC is capitalized and included in the principal. After the plant is completed, the principal amount is assigned an interest rate based on the U.S. Treasury yield curve prevailing in the year in which the plant is placed in service. *Id.* at §838l(g).

The U.S. Treasury rate for new capital investments prescribed in the Refinancing Act is:

> [A] rate determined by the Secretary of the Treasury, taking into consideration prevailing market yields, during the month preceding the beginning of the fiscal year in which the [new investment] . . . is placed in service, on outstanding interest-bearing obligations of the United States with periods to maturity comparable to the period between the beginning of the fiscal year and the repayment date for the new capital investment.

16 U.S.C. §838l(a)(6)(B).

The Refinancing Act also directed the Administrator to offer to provide assurance in new or existing power, transmission, or related service contracts that the government would not increase the repayment obligations in the future. *See*,16 U.S.C. §838l(i). The Refinancing Act also amends the Colville Settlement Act to modify the amount and timing of certain credits that BPA takes against its annual cash transfers to U.S. Treasury.

5.2 Allocation of Federal Columbia River Power System (FCRPS) Costs

In addition to power production, the individual generating projects comprising the FCRPS serve other purposes, including navigation, irrigation, recreation, and flood control. The total costs of these Federal projects are generally allocated according to the purposes they serve.

For projects that provide power resources to the FCRPS, this allocation has generally been accomplished pursuant to statutory direction. For example, Section 7 of the Bonneville Project Act, 16 U.S.C. §832f, requires that BPA's rates be based, *inter alia*, on "an allocation of costs made by the [Secretary of Energy,]" and, insofar as costs of the Bonneville Project were concerned:

> [T]he [Secretary of Energy] may allocate to the costs of electric facilities such a share of the cost of facilities having joint value for the production of electric energy and other purposes as the power development may fairly bear as compared with other such purposes.

Id.

Similar allocations for projects constructed pursuant to various Reclamation laws have been performed by the Secretary of the Interior under the authority of 43 U.S.C. §485h(a)-(b). Cost allocations for projects constructed by the COE have also been performed by the Secretary of the Army and approved by the Federal Power Commission (the predecessor to FERC).

On a generic level, an attempt is made to allocate the specific cost of each feature of a multi-purpose dam to the purpose it serves. For example, the costs of powerhouses, penstocks, and other specific power-related facilities have been allocated to power; whereas, the costs of navigation locks have been allocated to navigation. More problematic are the joint-use costs that remain unallocated after the specific costs identifiable to a single purpose have been allocated. The joint-use formulas attempt to account for the relative benefits provided by each function and costs are allocated accordingly.

Thus, costs assigned to the power production functions include specific cost items whose sole purpose is power production and the "power production share" of joint costs assigned to more than one purpose. Both types of costs are included in BPA's power revenue requirement.

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

Section 4(h)(10)(C) of the Northwest Power Act provides:

> The Administrator shall use the Bonneville Power Administration fund and the authorities available to the Administrator under [the Northwest Power Act] and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries . . .

16 U.S.C. §839b(h)(10)(A).

BPA is not obligated to reimburse the U.S. Treasury for the non-power portion of these fish and wildlife costs. Such non-power costs are instead allocated to the various project purposes by the BPA Administrator, in consultation with the COE and Reclamation, pursuant to Section 4(h)(10)(C) of the Northwest Power Act. 16 U.S.C. §839b(h)(10)(C). This allocation to various project purposes is intended to implement the principle that electric power consumers bear no greater share of the costs of fish and wildlife mitigation than the power portion of the project.

The legislative history of section 4(h)(10)(C) illustrates how the expenditures by the Administrator for protection, mitigation, and enhancement of fish and wildlife at individual Federal projects in excess of the portion allocable to electric consumers is to be treated as a credit for electric consumers. *See*, H.R. Rep. No. 976, 96th Cong., 2d Sess., pt. 2 at 45 (1980), reprinted in 1980 U.S.C.C.A.N. 5989, 6011. This principle is satisfied by treating expenditures on behalf of non-power purposes as other project costs. These amounts are regarded as having been applied towards other project costs properly allocable to the power function and payable to the U.S. Treasury. Thus, BPA receives a credit against its cash transfers to the U.S. Treasury for expenditures attributable to other project purposes. The cost-sharing arrangements with the Administration implement the section 4(h)(10)(C) directives.

BPA's initial funding of all the costs for fish and wildlife has the advantage of avoiding the need for funding the non-power portion of these costs through the annual appropriations process. For a further discussion of section 4(h)(10)(C) credits, *see*, Chapter 2.2 of this Study; Chapter 12 of Documentation, WP-07-E-BPA-02A; Chapter 5.2.3.3 of the Wholesale Power Rate Development Study, WP-07-E-BPA-05; and the Risk Analysis Study, WP-07-E-BPA-03, and Risk Analysis Study Documentation, WP-07-E-BPA-03A.

5.2.2 Equitable Allocation of Transmission Costs

In an order dated January 27, 1984, *United States Department of Energy--Bonneville Power Admin.*, 26 FERC 61,096 (1984), FERC directed BPA to, among other things, develop separate repayment studies for the generation and transmission functions of the FCRPS. The purpose of this requirement was to assist FERC in making the determination required under section 7(a)(2)(C) of the Northwest Power Act (16 U.S.C. §839e(a)(2)(C)) that transmission costs be equitably allocated between Federal and non-Federal use of the transmission system. This requirement has given BPA a twenty-one year history of conducting separate repayment studies for the transmission and generation functions, which has enabled BPA to transition to a bifurcated rate setting process with minimal change in repayment policy and development of the revenue requirement. Consistent with the decision to conduct bifurcated hearings for the transmission and generation functions beginning with the WP-02 proceeding, the Revenue Requirement Study incorporates only the separate repayment study for the generation function of the FCRPS for FY 2007-2009.

5.3 Repayment Requirements and Policies

The statutes do not include specific directives for scheduling repayment of the FCRPS capital appropriations and bonds issued to U.S. Treasury. The details of the repayment policy have largely been established through administrative interpretation of statutory requirements, with congressional sanction.

There have been a number of changes in BPA's repayment policy over the years concurrent with expansion of the FCRPS and changing conditions. In general, current repayment criteria were first approved by the Secretary of the Interior on April 3, 1963. These criteria were refined and submitted to the Secretary and the Federal Power Commission (the predecessor agency to FERC) in support of BPA's rate filing in September 1965.

The repayment policy was presented to Congress for its consideration for the authorization of the Grand Coulee Dam Third Powerhouse in June 1966. The underlying theory of repayment was discussed in the House of Representatives' Report related to this authorization, H.R. Rep. No. 1409, 89th Cong., 2d Sess. 9-10 (1966). As stated in that report:

> Accordingly, in a repayment study there is no annual schedule of capital repayment. The test of the sufficiency of revenues is whether the capital investment can be repaid within the overall repayment period established for each power project, each increment of investment in the transmission system, and each block of irrigation assistance. Hence, repayment may proceed at a faster or slower pace from year-to-year as conditions change.
>
> This approach to repayment scheduling has the effect of averaging the year-to-year variations in costs and revenues over the repayment period. This results in a uniform cost per unit of power sold, and permits the maintenance of stable rates for extended periods. It also facilitates the orderly marketing of power and permits Bonneville Power Administration's customers, which include both electric utilities and electro-process industries, to plan for the future with assurance.

The Secretary of the Interior issued a statement of power policy on September 30, 1970, setting forth general principles that reaffirmed the repayment policy as previously developed. The most pertinent of these principles are set forth in the Department of the Interior (DOI) Manual, Park 730, Chapter 1:

> A. Hydroelectric power, although not a primary objective, will be proposed to Congress and supported for inclusion in multiple-purpose Federal projects when . . . it is capable of repaying its share of the Federal investment, including operation and maintenance costs and interest, in accordance with the law.
>
> B. Electric power generated at Federal projects will be marketed at the lowest rates consistent with sound financial management. Rates for the sale of Federal electric power will be reviewed periodically to assure their sufficiency to repay operating and maintenance costs and the capital investment within 50 years with interest that more accurately reflects the cost of money.

To achieve a greater degree of uniformity in a repayment policy for all DOI power marketing agencies of which BPA was one at the time, the Deputy Assistant Secretary issued a memo on August 2, 1972 outlining: (1) a uniform definition of the commencement of the repayment period for a particular project; (2) the method for including future replacement costs in repayment studies; and (3) a provision that the investment or obligation bearing the highest interest rate shall be amortized first, to the extent possible, while still complying with the repayment period established for each increment of investment.

A further clarification of the repayment policy was outlined in a joint memo of January 7, 1974, from the Assistant Secretary for Reclamation and Assistant Secretary for Energy and Minerals. This memo states that in addition to meeting the overall objective of repaying the Federal investment or obligations within the prescribed repayment periods, revenues shall be adequate, except in unusual circumstances to repay annually all costs for O&M, purchased power, and interest.

On March 22, 1976, the DOI issued Chapter 4 of Part 730 of the DOI Manual to codify financial reporting requirements for the DOI's power marketing agencies. Included therein are standard policies and procedures for preparing system repayment studies.

BPA and other former DOI power marketing agencies were transferred to the newly established DOE on October 1, 1977. *See*,DOE Organization Act, 42 U.S.C. §7101 *et seq.* (1994). The DOE has adopted the policies set forth in Part 730 of the DOI Manual by issuing Interim Management Directive No. 1701 on September 28, 1977, which was subsequently replaced by RA 6120.2 on September 20, 1979, as amended on October 1, 1983.

The repayment policy outlined in RA 6120.2, paragraph 12, provides that BPA's total revenues from all sources must be sufficient to:

(1) Pay all annual costs of operating and maintaining the Federal power system;

(2) Pay the cost each FY of obtaining power through purchase and exchange agreements, the cost for transmission services, and other costs during the year in which such costs are incurred;

(3) Pay interest each year on the unamortized portion of the commercial power investment financed with appropriated funds at the interest rates established for each generating project and for each annual increment of such investment in the BPA transmission system, except that recovery of annual interest expense may be deferred in unusual circumstances for short periods of time,

(4) Pay when due the interest and amortization portion on outstanding bonds sold to the U.S. Treasury;

(5) Repay:

- each dollar of power investments and obligations in the FCRPS generating projects within 50 years after the projects become revenue producing (50 years has been deemed a "reasonable period" as intended by Congress, except for the Yakima-Chandler Project, which has a legislated amortization period of 66 years);
- each annual increment of transmission financed by Federal investments and obligations within the average service life of such transmission facilities (currently 45 years) or within a maximum of 50 years, whichever is less (BPA has interpreted RA 6120.2 to require repayment of bonds sold to finance conservation to be within the average service lives of these projects, currently estimated to be 20 years, and for fish and wildlife facilities to be 15 years).

- the Federally-financed amount of each replacement within its service life up to a maximum of 50 years; and

(6) As required by P.L. No. 89-448, repay the portion of construction costs at Federal reclamation projects that is beyond the repayment ability of the irrigators, and which is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their payments on construction costs.

The typical repayment period for appropriated capital investments is 50 years from the year in which the plant is placed in service. The Refinancing Act overrides provisions in RA 6120.2 related to determining interest during construction and assigning interest rates to Federal investments financed by appropriations. This Refinancing Act also contains provisions on repayment periods (due dates) for these investments. The Refinancing Act is discussed in section 5.1.3 of this chapter.

Irrigation costs are repaid without interest. P.L. No. 89-448 authorizes the payment of irrigation costs from revenues of the entire power system. This is consistent with the so-called "Basin Account" concept. P.L. No. 89-561, approved on September 7, 1966, amended P.L. No. 89-448 to provide several limitations on the repayment of irrigation costs from power revenues. These limitations are:

(1) the irrigation costs are to be paid from "net revenues" of the power system, with net revenues defined as those revenues over and above the amount needed to cover power costs and previously authorized irrigation payments;

(2) the construction of new Federal irrigation projects will be scheduled, *i.e.*, deferred, if necessary, so that the repayment of the irrigation costs from power revenues will not require an increase in the BPA power rate level; and

(3) the total amount of irrigation costs to be repaid from power revenues shall not average more than $30 million per year in any period of 20 consecutive years.

In addition, other sections within RA 6120.2 require that any outstanding deferred interest payments must be repaid before any planned amortization payments are made. Also, repayments are to be made by amortizing those Federal investments and obligations bearing the highest interest rate first, to the extent possible, while still completing repayment of each increment of Federal investment and obligation within its prescribed repayment period.

Table 5A

GENERATION REVENUE REQUIREMENT
INCOME STATEMENT
($000s)

		A 2007	B 2008	C 2009
1	OPERATING EXPENSES			
2	POWER SYSTEM GENERATION RESOURCES			
3	OPERATING GENERATION RESOURCES	514,139	471,856	512,425
4	OPERATING GENERATION SETTLEMENT PAYMENTS	16,968	17,354	17,749
5	NON-OPERATING GENERATION	9,350	5,252	2,254
6	CONTRACTED POWER PURCHASES	181,652	150,340	175,435
7	RESIDENTIAL EXCHANGE/IOU SETTLEMENT BENEFITS	301,000	301,000	301,000
8	RENEWABLE AND CONSERVATION GENERATION	103,011	107,873	129,547
9	TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	181,962	182,962	185,662
10	POWER NON-GENERATION OPERATIONS	56,132	57,715	59,422
11	F&W/ENVIRONMENTAL REQUIREMENTS	171,185	172,276	173,367
12	GENERAL AND ADMINISTRATIVE	61,165	61,127	67,519
13	OTHER INCOME, EXPENSES AND ADJUSTMENTS	59,000	59,000	59,000
14	NON-FEDERAL DEBT SERVICE	601,403	593,923	598,015
15	DEPRECIATION AND AMORTIZATION	186,671	192,838	199,779
16	TOTAL OPERATING EXPENSES	2,443,637	2,373,515	2,481,173
17	INTEREST EXPENSE:			
18	INTEREST ON FEDERAL INVESTMENT-			
19	APPROPRIATED FUNDS	200,621	197,658	200,289
20	BONDS ISSUED TO U.S. TREASURY	60,059	77,018	87,641
21	INTEREST CREDIT ON CASH RESERVES	(27,852)	(32,946)	(37,531)
22	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	613	185
23	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)
24	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(8,000)	(8,000)	(8,000)
25	NET INTEREST EXPENSE	179,504	188,406	196,646
26	TOTAL EXPENSES	2,623,142	2,561,921	2,677,820
27	MINIMUM REQUIRED NET REVENUES 1/	34,105	42,876	27,599
28	PLANNED NET REVENUES FOR RISK	97,000	97,000	97,000
29	TOTAL PLANNED NET REVENUES (27+28)	131,105	139,876	124,599
30	**TOTAL REVENUE REQUIREMENT**	**2,754,247**	**2,701,797**	**2,802,418**

1/ SEE NOTE ON CASH FLOW STATEMENT

Table 5B

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

		A 2007	B 2008	C 2009
1	CASH FROM OPERATING ACTIVITIES			
2	MINIMUM REQUIRED NET REVENUES 1/	34,105	42,876	27,599
3	NON-CASH ITEMS:			
4	DEPRECIATION AND AMORTIZATION	186,671	192,838	199,779
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	613	185
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)
7	ACCRUAL REVENUES	(5,179)	(5,179)	(5,179)
8	CASH PROVIDED BY OPERATING ACTIVITIES	170,273	185,211	176,447
9	CASH FROM INVESTMENT ACTIVITIES:			
10	INVESTMENT IN:			
11	UTILITY PLANT (INCLUDING AFUDC)	(209,119)	(280,796)	(142,817)
12	CONSERVATION	(32,000)	(32,000)	(32,000)
13	FISH & WILDLIFE	(36,000)	(36,000)	(36,000)
14	CASH USED FOR INVESTMENT ACTIVITIESS	(277,119)	(348,796)	(210,817)
15	CASH FROM BORROWING AND APPROPRIATIONS:			
16	INCREASE IN BONDS ISSUED TO U.S. TREASURY	201,000	213,000	205,000
17	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(68,357)	(104,300)	(59,220)
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	76,119	135,796	5,817
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(101,916)	(77,961)	(110,637)
20	PAYMENT OF IRRIGATION ASSISTANCE	0	(2,950)	(6,590)
21	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	106,846	163,585	34,370
22	ANNUAL INCREASE (DECREASE) IN CASH	0	0	0
23	PLANNED NET REVENUES FOR RISK	97,000	97,000	97,000
24	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	97,000	97,000	97,000

1/ Line 22 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.

Table 6A

GENERATION CURRENT REVENUE TEST
INCOME STATEMENT
($000s)

		A 2007	B 2008	C 2009
1	REVENUES FROM CURRENT RATES	2,473,471	2,395,963	2,350,868
2	OPERATING EXPENSES			
3	POWER SYSTEM GENERATION RESOURCES			
4	OPERATING GENERATION RESOURCES	514,139	471,856	512,425
5	OPERATING GENERATION SETTLEMENT PAYMENTS	16,968	17,354	17,749
6	NON-OPERATING GENERATION	9,350	5,252	2,254
7	CONTRACTED POWER PURCHASES	150,622	132,854	144,061
8	RESIDENTIAL EXCHANGE/IOU SETTLEMENT BENEFITS	301,000	301,000	301,000
9	RENEWABLE AND CONSERVATION GENERATION	103,011	107,873	129,547
10	TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	181,962	182,962	185,662
11	POWER NON-GENERATION OPERATIONS	56,132	57,715	59,422
12	F&W/ENVIRONMENTAL REQUIREMENTS	171,185	172,276	173,367
13	GENERAL AND ADMINISTRATIVE	61,165	61,127	67,519
14	OTHER INCOME, EXPENSES AND ADJUSTMENTS	59,000	59,000	59,000
15	NON-FEDERAL DEBT SERVICE	601,403	593,923	598,015
16	DEPRECIATION AND AMORTIZATION	186,671	192,838	199,779
17	TOTAL OPERATING EXPENSES	2,412,607	2,356,029	2,449,799
18	INTEREST EXPENSE:			
19	INTEREST ON FEDERAL INVESTMENT-			
20	APPROPRIATED FUNDS	200,621	197,658	200,289
21	BONDS ISSUED TO U.S. TREASURY	60,059	77,018	87,641
22	INTEREST CREDIT ON CASH RESERVES	(21,259)	(12,130)	1,787
23	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	613	185
24	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)
25	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(8,000)	(8,000)	(8,000)
26	NET INTEREST EXPENSE	186,097	209,222	235,964
27	TOTAL EXPENSES	2,598,705	2,565,251	2,685,764
28	NET REVENUES	(125,234)	(169,288)	(334,896)

Table 6B

GENERATION CURRENT REVENUE TEST
STATEMENT OF CASH FLOWS
($000s)

		A 2007	B 2008	C 2009
1	CASH FROM OPERATING ACTIVITIES			
2	NET REVENUES	(125,234)	(169,288)	(334,896)
3	NON-CASH ITEMS:			
4	DEPRECIATION AND AMORTIZATION	186,671	192,838	199,779
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	613	185
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)
7	ACCRUAL REVENUES	(5,179)	(5,179)	(5,179)
8	CASH PROVIDED BY OPERATING ACTIVITIES	10,934	(26,953)	(186,047)
9	CASH FROM INVESTMENT ACTIVITIES:			
10	INVESTMENT IN:			
11	UTILITY PLANT (INCLUDING AFUDC)	(209,119)	(280,796)	(142,817)
12	CONSERVATION	(32,000)	(32,000)	(32,000)
13	FISH & WILDLIFE	(36,000)	(36,000)	(36,000)
14	CASH USED FOR INVESTMENT ACTIVITIESS	(277,119)	(348,796)	(210,817)
15	CASH FROM BORROWING AND APPROPRIATIONS:			
16	INCREASE IN BONDS ISSUED TO U.S. TREASURY	201,000	213,000	205,000
17	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(68,357)	(104,300)	(59,220)
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	76,119	135,796	5,817
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(101,916)	(77,961)	(110,637)
20	PAYMENT OF IRRIGATION ASSISTANCE	0	(2,950)	(6,590)
21	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	106,846	163,585	34,370
22	ANNUAL INCREASE (DECREASE) IN CASH	(159,339)	(212,164)	(362,494)

Table 7
FEDERAL COLUMBIA RIVER POWER SYSTEM
GENERATION REVENUES FROM CURRENT RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000s)

	A	B	C	D	E	F	G	H	I	J	K
YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION 2/ (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
GENERATION											
1978	217,534	40,331	51,130	36,511	81,883	7,679	46,521	54,200	6,937		47,263
1979	189,542	49,347	25,195	39,083	98,889	(22,972)	42,586	19,614	914		18,700
1980	341,863	76,460	182,743	41,237	105,740	(64,317)	94,441	30,124	73		30,051
1981	502,589	92,990	269,625	42,870	118,861	(21,757)	48,941	27,184	4,410 3/		22,774
1982	1,067,604	115,430	945,442	49,355	145,610	(188,233)	55,427	(132,806)	0		(132,806)
1983	1,485,741	114,960	1,255,810	57,967	153,763	(96,759)	64,039	(32,720)	0		(32,720)
1984	2,248,654	146,870	1,898,859	67,644	170,942	(35,661)	257,382	221,721	192,294 4/		29,427
1985	2,371,829	137,664	1,898,178	75,711	173,888	86,388	75,711	162,099	37,354		124,745
1986	2,179,326	135,632	1,895,153	84,162	175,257	(110,878)	84,162	(26,716)	10,587		(37,303)
1987	2,014,040	154,184	1,826,711	91,552	199,448	(257,855)	91,552	(166,303)	2,471		(168,774)
1988	2,303,479	183,326	1,796,029	98,288	204,416	21,420	98,288	119,708	149,778		(30,070)
1989	2,273,508	173,694	1,760,205	100,104	189,446	50,059	100,104	150,163	32,875		117,288
1990	2,315,035	198,721	1,527,829	105,338	197,462	285,685	105,338	391,023	63,336		327,687
1991	2,482,482	216,777	1,572,046	103,047	167,559	423,053	103,047	526,100	114,583		411,517
1992	2,142,645	287,360	1,821,930	110,403	169,711	(246,759)	110,403	(136,356)	57,543		(193,899)
1993	2,233,989	309,915	1,868,863	118,143	186,455	(249,387)	118,143	(131,244)	117,974		(249,218)
1994	2,536,059	316,352	1,934,944	125,396	197,222	(37,855)	125,396	87,541	135,018		(47,477)
1995	2,704,285	327,420	1,915,529	141,798	215,850	103,688	141,798	245,486	196,544		48,942
1996	2,744,510	366,808	1,959,406	151,122	208,509	58,665	154,024	197,689 5/	135,010		62,679
1997	1,996,439	612,961	924,789	148,215	197,238	113,236	105,956	219,192	82,971	25,143	111,078
1998	2,060,750	665,005	1,091,678	162,562	201,930	(60,425)	118,892	76,812	61,000		15,812
1999	2,366,423	702,717	1,196,308	162,008	182,079	123,311	118,951	311,083	25,000		286,083
2000	2,720,940	723,377	1,410,029	165,874	169,320	252,340	119,184	366,345	175,338		191,007
2001	3,888,051	766,244	2,998,914	168,433	166,504	(212,044)	121,506	(143,594)	151,062	16,560	(311,216)
2002	3,047,803	992,628	1,766,850	174,164	201,582	(87,421)	127,491	(3,413)	369,800		(373,213)
2003	3,144,811	649,663	1,896,661	178,896	176,595	242,996	131,592	314,144	73,000		241,144
2004	2,738,898	655,568	1,424,246	177,298	162,531	319,255	129,789	354,413	233,000	739	120,674
COST EVALUATION PERIOD											
2005	2,737,791	673,245	1,472,020	177,667	166,965	247,894	132,343	366,930	271,297		95,633
2006	2,771,770	705,585	1,529,581	184,677	171,725	180,202	139,353	314,426	261,476		52,950
RATE APPROVAL PERIOD											
2007	2,473,471	795,086	1,430,851	186,671	186,097	(125,234)	141,347	10,934	170,273		(159,339)
2008	2,395,963	804,495	1,358,696	192,838	209,222	(169,288)	147,514	(26,953)	182,261	2,950	(212,164)
2009	2,350,868	823,952	1,426,069	199,779	235,964	(334,896)	154,027	(186,047)	169,857	6,590	(362,494)
REPAYMENT PERIOD											
2010	2,350,868	823,952	1,445,044	199,779	222,556	(340,463)	154,027	(191,615)	154,497	0	(346,113)
2011	2,350,868	823,952	1,453,154	199,779	221,011	(347,028)	154,027	(198,180)	147,933	0	(346,113)
2012	2,350,868	823,952	1,539,595	199,779	222,184	(434,642)	154,027	(285,794)	59,612	706	(346,113)
2013	2,350,868	823,952	1,397,602	199,779	222,755	(293,220)	154,027	(144,372)	157,563	44,178	(346,113)
2014	2,350,868	823,952	1,347,838	199,779	219,247	(239,948)	154,027	(91,100)	212,269	42,744	(346,113)

YEAR	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C PURCHASE AND EXCHANGE POWER (STATEMENT E)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION 2/ (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	J IRRIGATION AMORTIZATION (STATEMENT C)	K NET POSITION (K=H-I-J)
2015	2,350,868	823,952	1,334,831	199,779	211,669	(219,364)	154,027	(70,516)	190,311	85,286	(346,113)
2016	2,350,868	823,952	1,540,866	199,779	210,114	(423,843)	154,027	(274,995)	0	71,118	(346,113)
2017	2,350,868	823,952	1,603,295	199,779	218,798	(494,956)	154,027	(346,108)	0	2	(346,110)
2018	2,350,868	823,952	1,462,744	199,779	222,712	(358,318)	154,027	(209,470)	113,699	22,943	(346,113)
2019	2,350,868	823,952	1,188,346	199,779	215,367	(76,575)	154,027	72,273	360,569	57,816	(346,113)
2020	2,350,868	823,952	1,188,491	199,779	196,903	(58,256)	154,027	90,592	403,973	32,731	(346,113)
2021	2,350,868	823,952	1,188,650	199,779	175,553	(37,066)	154,027	111,782	442,974	14,920	(346,113)
2022	2,350,868	823,952	1,188,822	199,779	159,358	(21,042)	154,027	127,806	460,600	13,318	(346,113)
2023	2,350,868	823,952	1,189,411	199,779	126,606	11,120	154,027	159,968	496,468	9,613	(346,113)
2024	2,350,868	823,952	1,189,602	199,779	98,977	38,557	154,027	187,405	512,370	21,148	(346,113)
2025	2,350,868	823,952	1,175,832	199,779	69,107	82,198	154,027	231,046	565,925	11,234	(346,113)
2026	2,350,868	823,952	1,175,681	199,779	51,719	99,737	154,027	248,585	576,569	18,128	(346,113)
2027	2,350,868	823,952	1,175,916	199,779	3,764	147,457	154,027	296,305	637,033	5,385	(346,113)
2028	2,350,868	823,952	1,176,165	199,779	(33,588)	184,559	154,027	333,407	411,394	207,391	(285,378)
2029	2,350,868	823,952	1,176,433	199,779	(52,257)	202,962	154,027	351,810	49,119	0	302,691
2030	2,350,868	823,952	1,176,719	199,779	(52,250)	202,669	154,027	351,517	44,228	0	307,289
2031	2,350,868	823,952	1,177,024	199,779	(52,243)	202,357	154,027	351,205	39,875	0	311,330
2032	2,350,868	823,952	1,177,350	199,779	(52,236)	202,022	154,027	350,870	36,033	0	314,837
2033	2,350,868	823,952	1,177,699	199,779	(52,227)	201,665	154,027	350,513	51,481	0	299,032
2034	2,350,868	823,952	1,178,072	199,779	(52,218)	201,284	154,027	350,132	51,949	0	298,183
2035	2,350,868	823,952	1,178,470	199,779	(52,209)	200,876	154,027	349,724	72,461	0	277,263
2036	2,350,868	823,952	1,178,895	199,779	(53,421)	201,664	154,027	350,512	77,957	0	272,555
2037	2,350,868	823,952	1,179,349	199,779	(55,184)	202,972	154,027	351,820	53,494	0	298,326
2038	2,350,868	823,952	1,179,835	199,779	(55,172)	202,475	154,027	351,323	79,070	0	272,253
2039	2,350,868	823,952	1,180,353	199,779	(56,878)	203,662	154,027	352,510	79,684	0	272,826
2040	2,350,868	823,952	1,180,908	199,779	(58,582)	204,811	154,027	353,659	105,280	0	248,379
2041	2,350,868	823,952	1,181,500	199,779	(61,851)	207,488	154,027	356,336	55,911	0	300,425
2042	2,350,868	823,952	1,182,133	199,779	(61,836)	206,840	154,027	355,688	116,577	0	239,111
2043	2,350,868	823,952	1,182,809	199,779	(65,880)	210,208	154,027	359,056	93,302	0	308,836
2044	2,350,868	823,952	1,183,532	199,779	(68,485)	212,090	154,027	360,938	50,220	0	313,564
2045	2,350,868	823,952	1,184,304	199,779	(68,467)	211,300	154,027	360,148	47,374	0	312,774
2046	2,350,868	823,952	1,185,128	199,779	(68,448)	210,456	154,027	359,304	44,703	0	314,601
2047	2,350,868	823,952	1,186,010	199,779	(68,427)	209,554	154,027	358,402	42,201	0	316,201
2048	2,350,868	823,952	1,186,952	199,779	(68,405)	208,590	154,027	357,438	39,862	0	317,576
2049	2,350,868	823,952	1,187,958	199,779	(68,381)	207,559	154,027	356,407	35,966	0	320,441
2050	2,350,868	823,952	1,189,033	199,779	(68,355)	206,459	154,027	355,307	32,499	0	322,808
2051	2,350,868	823,952	1,190,182	199,779	(68,328)	205,283	154,027	354,131	29,444	0	324,687
2052	2,350,868	823,952	1,191,410	199,779	(68,299)	204,026	154,027	352,874	26,740	0	326,134
2053	2,350,868	823,952	1,192,722	199,779	(68,268)	202,683	154,027	351,531	41,875	0	309,656
2054	2,350,868	823,952	1,104,736	199,779	(70,349)	292,750	154,027	441,598	42,436	0	399,162
2055	2,350,868	823,952	1,191,410	199,779	(76,665)	212,392	154,027	361,240	43,028	0	318,212
2056	2,350,868	823,952	1,192,722	199,779	(76,665)	211,080	154,027	359,928	43,649	0	316,279
2057	2,350,868	823,952	1,104,736	199,779	(76,665)	299,066	154,027	447,914	44,255	0	403,659
2058	2,350,868	823,952	837,679	199,779	(76,665)	566,123	154,027	714,971	44,890	0	670,081
2059	2,350,868	823,952	837,679	199,779	(76,665)	566,123	154,027	714,971	45,553	0	669,418
GENERATION TOTALS	174,837,752	50,092,607	101,963,717	12,908,868	7,034,818	2,837,742	10,536,463	12,922,551	9,394,900	710,642	1,430,302

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.

2/MAY INCLUDE ADJUSTMENTS FOR ACCRUAL REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.

3/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

4/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

5/REDUCED BY $15,000 OF REVENUE FINANCING.

Table 8A

GENERATION REVISED REVENUE TEST
INCOME STATEMENT
($000s)

		A 2007	B 2008	C 2009
1	REVENUES FROM PROPOSED RATES	2,837,639	2,759,352	2,706,905
2	OPERATING EXPENSES			
3	POWER SYSTEM GENERATION RESOURCES			
4	OPERATING GENERATION RESOURCES	514,139	471,856	512,425
5	OPERATING GENERATION SETTLEMENT PAYMENTS	16,968	17,354	17,749
6	NON-OPERATING GENERATION	9,350	5,252	2,254
7	CONTRACTED POWER PURCHASES	150,622	132,854	144,061
8	RESIDENTIAL EXCHANGE/IOU SETTLEMENT BENEFITS	301,000	301,000	301,000
9	RENEWABLE AND CONSERVATION GENERATION	103,011	107,873	129,547
10	TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	181,962	182,962	185,662
11	POWER NON-GENERATION OPERATIONS	56,132	57,715	59,422
12	F&W/ENVIRONMENTAL REQUIREMENTS	171,185	172,276	173,367
13	GENERAL AND ADMINISTRATIVE	61,165	61,127	67,519
14	OTHER INCOME, EXPENSES AND ADJUSTMENTS	59,000	59,000	59,000
15	NON-FEDERAL DEBT SERVICE	601,403	593,923	598,015
16	DEPRECIATION AND AMORTIZATION	186,671	192,838	199,779
17	TOTAL OPERATING EXPENSES	2,412,607	2,356,029	2,449,799
18	INTEREST EXPENSE:			
19	INTEREST ON FEDERAL INVESTMENT-			
20	APPROPRIATED FUNDS	200,621	197,658	200,289
21	BONDS ISSUED TO U.S. TREASURY	60,059	77,018	87,641
22	INTEREST CREDIT ON CASH RESERVES	(29,908)	(38,058)	(41,228)
23	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	613	185
24	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)
25	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(8,000)	(8,000)	(8,000)
26	NET INTEREST EXPENSE	177,448	183,294	192,949
27	TOTAL EXPENSES	2,590,056	2,539,323	2,642,749
28	NET REVENUES	247,583	220,029	64,156

Table 8B

GENERATION REVISED REVENUE TEST
STATEMENT OF CASH FLOWS
($000s)

		A 2007	B 2008	C 2009
1	CASH FROM OPERATING ACTIVITIES			
2	NET REVENUES	247,583	220,029	64,156
3	NON-CASH ITEMS:			
4	DEPRECIATION AND AMORTIZATION	186,671	192,838	199,779
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	613	613	185
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)	(45,937)
7	ACCRUAL REVENUES	(5,179)	(5,179)	(5,179)
8	CASH PROVIDED BY OPERATING ACTIVITIES	383,751	362,364	213,005
9	CASH FROM INVESTMENT ACTIVITIES:			
10	INVESTMENT IN:			
11	UTILITY PLANT (INCLUDING AFUDC)	(209,119)	(280,796)	(142,817)
12	CONSERVATION	(32,000)	(32,000)	(32,000)
13	FISH & WILDLIFE	(36,000)	(36,000)	(36,000)
14	CASH USED FOR INVESTMENT ACTIVITIESS	(277,119)	(348,796)	(210,817)
15	CASH FROM BORROWING AND APPROPRIATIONS:			
16	INCREASE IN BONDS ISSUED TO U.S. TREASURY	201,000	213,000	205,000
17	REPAYMENT OF BONDS ISSUED TO U.S. TREASURY	(68,357)	(104,300)	(59,220)
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	76,119	135,796	5,817
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(101,916)	(77,961)	(110,637)
20	PAYMENT OF IRRIGATION ASSISTANCE	0	(2,950)	(6,590)
21	CASH PROVIDED BY BORROWING AND APPROPRIATIONS	106,846	163,585	34,370
22	ANNUAL INCREASE (DECREASE) IN CASH	213,478	177,153	36,558

Table 9
FEDERAL COLUMBIA RIVER POWER SYSTEM
GENERATION REVENUES FROM PROPOSED RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

YEAR	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C PURCHASE AND EXCHANGE POWER (STATEMENT E)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION 2/ (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	J IRRIGATION AMORTIZATION (STATEMENT C)	K NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
GENERATION											
1978	217,534	40,331	51,130	36,511	81,883	7,679	46,521	54,200	6,937		47,263
1979	189,542	49,347	25,195	39,083	98,889	(22,972)	42,586	19,614	914		18,700
1980	341,863	76,460	182,743	41,237	105,740	(64,317)	94,441	30,124	73		30,051
1981	502,589	92,990	269,625	42,870	118,861	(21,757)	48,941	27,184	4,410 3/		22,774
1982	1,067,604	115,430	945,442	49,355	145,610	(188,233)	55,427	(132,806)	0		(132,806)
1983	1,485,741	114,960	1,255,810	57,967	153,763	(96,759)	64,039	(32,720)	0		(32,720)
1984	2,248,654	146,870	1,898,859	67,644	170,942	(35,661)	257,382	221,721	192,294 4/		29,427
1985	2,371,829	137,664	1,898,178	75,711	173,888	86,388	75,711	162,099	37,354		124,745
1986	2,179,326	135,632	1,895,153	84,162	175,257	(110,878)	84,162	(26,716)	10,587		(37,303)
1987	2,014,040	154,184	1,826,711	91,552	199,448	(257,855)	91,552	(166,303)	2,471		(168,774)
1988	2,303,479	183,326	1,796,029	98,288	204,416	21,420	98,288	119,708	149,778		(30,070)
1989	2,273,508	173,694	1,760,205	100,104	189,446	50,059	100,104	150,163	32,875		117,288
1990	2,315,035	198,721	1,527,829	105,338	197,462	285,685	105,338	391,023	63,336		327,687
1991	2,482,482	216,777	1,572,046	103,047	167,559	423,053	103,047	526,100	114,583		411,517
1992	2,142,645	287,360	1,821,930	110,403	169,711	(246,759)	110,403	(136,356)	57,543		(193,899)
1993	2,233,989	309,915	1,868,863	118,143	186,455	(249,387)	118,143	(131,244)	117,974		(249,218)
1994	2,536,059	316,352	1,934,944	125,396	197,222	(37,855)	125,396	87,541	135,018		(47,477)
1995	2,704,285	327,420	1,915,529	141,798	215,850	103,688	141,798	245,486	196,544		48,942
1996	2,744,510	366,808	1,959,406	151,122	208,509	58,665	154,024	197,689 5/	135,010		62,679
1997	1,996,439	612,961	924,789	148,215	197,238	113,236	105,956	219,192	82,971	25,143	111,078
1998	2,060,750	665,005	1,091,678	162,562	201,930	(60,425)	118,892	76,812	61,000		15,812
1999	2,366,423	702,717	1,196,308	162,008	182,079	123,311	118,951	311,083	25,000		286,083
2000	2,720,940	723,377	1,410,029	165,874	169,320	252,340	119,184	366,345	175,338		191,007
2001	3,888,051	766,244	2,998,914	168,433	166,504	(212,044)	121,506	(143,594)	151,062	16,560	(311,216)
2002	3,047,803	992,628	1,766,850	174,164	201,582	(87,421)	127,491	(3,413)	369,800		(373,213)
2003	3,144,811	649,663	1,896,661	178,896	176,595	242,996	131,592	314,144	73,000		241,144
2004	2,738,898	655,568	1,424,246	177,298	162,531	319,255	129,789	354,413	233,000	739	120,674
COST EVALUATION PERIOD											
2005	2,737,791	673,245	1,472,020	177,667	166,965	247,894	132,343	366,930	271,297		95,633
2006	2,771,770	705,585	1,529,581	184,677	171,725	180,202	139,353	314,426	261,476		52,950
RATE APPROVAL PERIOD											
2007	2,837,639	795,086	1,430,851	186,671	177,448	247,583	141,347	383,751	170,273		213,478
2008	2,759,352	804,495	1,358,696	192,838	183,294	220,029	147,514	362,364	182,261	2,950	177,153
2009	2,706,905	823,952	1,426,069	199,779	192,949	64,156	154,028	213,005	169,857	6,590	36,558
REPAYMENT PERIOD											
2010	2,706,905	823,952	1,445,044	199,779	180,358	57,772	154,028	206,621	154,497	0	52,123
2011	2,706,905	823,952	1,453,154	199,779	178,813	51,207	154,028	200,056	147,933	0	52,123
2012	2,706,905	823,952	1,539,595	199,779	179,986	(36,407)	154,028	112,442	59,612	706	52,123
2013	2,706,905	823,952	1,397,602	199,779	180,557	105,015	154,028	253,864	157,563	44,178	52,124
2014	2,706,905	823,952	1,347,838	199,779	177,049	158,287	154,028	307,136	212,269	42,744	52,123

YEAR	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C PURCHASE AND EXCHANGE POWER (STATEMENT E)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION 2/ (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	J IRRIGATION AMORTIZATION (STATEMENT C)	K NET POSITION (K=H-I-J)
2015	2,706,905	823,952	1,334,831	199,779	169,471	178,871	154,028	327,720	190,311	85,286	52,123
2016	2,706,905	823,952	1,540,866	199,779	167,916	(25,608)	154,028	123,241	0	71,118	52,123
2017	2,706,905	823,952	1,603,295	199,779	176,600	(96,721)	154,028	52,128	0	2	52,126
2018	2,706,905	823,952	1,462,744	199,779	180,514	39,917	154,028	188,766	113,699	22,943	52,123
2019	2,706,905	823,952	1,188,346	199,779	173,169	321,660	154,028	470,509	360,569	57,816	52,123
2020	2,706,905	823,952	1,188,491	199,779	154,705	339,979	154,028	488,828	403,973	32,731	52,123
2021	2,706,905	823,952	1,188,650	199,779	133,355	361,169	154,028	510,018	442,974	14,920	52,123
2022	2,706,905	823,952	1,188,822	199,779	117,160	377,193	154,028	526,042	460,600	13,318	52,123
2023	2,706,905	823,952	1,189,411	199,779	84,408	409,355	154,028	558,204	496,468	9,613	52,123
2024	2,706,905	823,952	1,189,602	199,779	56,779	436,792	154,028	585,641	512,370	21,148	52,123
2025	2,706,905	823,952	1,175,832	199,779	26,909	480,433	154,028	629,282	565,925	11,234	52,123
2026	2,706,905	823,952	1,175,681	199,779	9,521	497,972	154,028	646,821	576,569	18,128	52,123
2027	2,706,905	823,952	1,175,916	199,779	(38,434)	545,692	154,028	694,541	637,033	5,385	52,123
2028	2,706,905	823,952	1,176,165	199,779	(75,786)	582,794	154,028	731,643	411,394	207,391	112,858
2029	2,706,905	823,952	1,176,433	199,779	(94,455)	601,197	154,028	750,046	49,119	0	700,927
2030	2,706,905	823,952	1,176,719	199,779	(94,448)	600,904	154,028	749,753	44,228	0	705,525
2031	2,706,905	823,952	1,177,024	199,779	(94,441)	600,592	154,028	749,441	39,875	0	709,566
2032	2,706,905	823,952	1,177,350	199,779	(94,434)	600,257	154,028	749,106	36,033	0	713,073
2033	2,706,905	823,952	1,177,699	199,779	(94,425)	599,900	154,028	748,749	51,481	0	697,268
2034	2,706,905	823,952	1,178,072	199,779	(94,416)	599,519	154,028	748,368	51,949	0	696,419
2035	2,706,905	823,952	1,178,470	199,779	(94,407)	599,111	154,028	747,960	72,461	0	675,499
2036	2,706,905	823,952	1,178,895	199,779	(95,619)	599,899	154,028	748,748	77,957	0	670,791
2037	2,706,905	823,952	1,179,349	199,779	(97,382)	601,207	154,028	750,056	53,494	0	696,562
2038	2,706,905	823,952	1,179,835	199,779	(97,370)	600,710	154,028	749,559	79,070	0	670,489
2039	2,706,905	823,952	1,180,353	199,779	(99,076)	601,897	154,028	750,746	79,684	0	671,062
2040	2,706,905	823,952	1,180,908	199,779	(100,780)	603,046	154,028	751,895	105,280	0	646,615
2041	2,706,905	823,952	1,181,500	199,779	(104,049)	605,723	154,028	754,572	55,911	0	698,661
2042	2,706,905	823,952	1,182,133	199,779	(104,034)	605,075	154,028	753,924	116,577	0	637,347
2043	2,706,905	823,952	1,182,809	199,779	(108,078)	608,443	154,028	757,292	93,302	0	707,072
2044	2,706,905	823,952	1,183,532	199,779	(110,683)	610,325	154,028	759,174	50,220	0	711,800
2045	2,706,905	823,952	1,184,304	199,779	(110,665)	609,535	154,028	758,384	47,374	0	711,010
2046	2,706,905	823,952	1,185,128	199,779	(110,646)	608,691	154,028	757,540	44,703	0	712,837
2047	2,706,905	823,952	1,186,010	199,779	(110,625)	607,789	154,028	756,638	42,201	0	714,437
2048	2,706,905	823,952	1,186,952	199,779	(110,603)	606,825	154,028	755,674	39,862	0	715,812
2049	2,706,905	823,952	1,187,958	199,779	(110,579)	605,794	154,028	754,643	35,966	0	718,677
2050	2,706,905	823,952	1,189,033	199,779	(110,553)	604,694	154,028	753,543	32,499	0	721,044
2051	2,706,905	823,952	1,190,182	199,779	(110,526)	603,518	154,028	752,367	29,444	0	722,923
2052	2,706,905	823,952	1,191,410	199,779	(110,497)	602,261	154,028	751,110	26,740	0	724,370
2053	2,706,905	823,952	1,192,722	199,779	(110,466)	600,918	154,028	749,767	41,875	0	707,892
2054	2,706,905	823,952	1,104,736	199,779	(112,547)	690,985	154,028	839,834	42,436	0	797,398
2055	2,706,905	823,952	1,191,410	199,779	(118,863)	610,627	154,028	759,476	43,028	0	716,448
2056	2,706,905	823,952	1,192,722	199,779	(118,863)	609,315	154,028	758,164	43,649	0	714,515
2057	2,706,905	823,952	1,104,736	199,779	(118,863)	697,301	154,028	846,150	44,255	0	801,895
2058	2,706,905	823,952	837,679	199,779	(118,863)	964,358	154,028	1,113,207	44,890	0	1,068,317
2059	2,706,905	823,952	837,679	199,779	(118,863)	964,358	154,028	1,113,207	45,553	0	1,067,654
GENERATION TOTALS	191,943,011	50,092,607	101,963,717	12,908,868	5,058,316	21,919,503	10,536,509	32,004,357	9,394,900	710,642	20,512,108

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.

2/MAY INCLUDE ADJUSTMENTS FOR ACCRUAL REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.

3/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

4/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

5/REDUCED BY $15,000 OF REVENUE FINANCING.

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APPENDIX A

POWER FUNCTION REVIEW

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Department of Energy

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

POWER BUSINESS LINE

June 24, 2005

In reply refer to: P-6

To Our Customers, Constituents, Tribes and Other Stakeholders:

The Bonneville Power Administration (BPA) is now concluding the Power Function Review (PFR), which began in January 2005. Following a 4-month process of program reviews, BPA issued a draft report to the region for comment on May 2, 2005. Two closeout meetings were then held with both the PFR technical- and management-level participants. The comment period closed on May 20, 2005. The PFR process sought to provide interested parties with meaningful opportunities to examine, understand, and provide input on the cost projections that would form the basis for the FY 2007 wholesale initial power rate proposal, which is expected in the fall of 2005. BPA has found the PFR process to be beneficial and appreciates the time, energy, and attention participants gave to this effort.

We believe the cost levels included in the attached report represent a good public policy balance between near-term and long-term impacts. However, the conclusions on program cost levels presented in the report were reached before the preliminary injunction on river operations was issued. This preliminary injunction calls for significant additional spill this summer, creating an expected $67 million revenue effect to ratepayers in 2005.

The preliminary injunction is under appeal, and, therefore the cost implications for FY 2006-2009 of the 2004 Biological Opinion are not yet known. Despite this uncertainty, BPA has decided to move forward with the final PFR report without modifications. BPA will review all the PFR decisions after the impact of this ruling and associated appeals become more clear. PFR decisions will be reviewed and further reductions in PFR program cost levels may be necessary before the FY 2007-2009 final power rate proposal is developed next year if the generation and revenue losses are significant and persistent.

Overall, cost reductions totaling $96 million per year for the FY 2007-2009 period have been identified through the PFR process. These reductions are detailed in the attached report. Cost forecasts for BPA's initial power rate proposal, due this fall, must be finalized now to allow the rates process to stay on schedule. BPA will use the numbers in the attached report for this purpose. However, many commenters noted that these reductions are not enough. BPA is also not satisfied that these costs are as low as they can reasonably be while still meeting its mission requirements. BPA will take the following steps to seek further reductions before submitting its FY 2007-2009 final power rate proposal in mid-2006:

- Conduct head-to-head benchmarking of Federal hydro project costs against Mid-Columbia and other regional hydro projects. BPA, the Corps of Engineers, Bureau of Reclamation, and Grant PUD have agreed to this effort.
- Potentially remove the Calpine geothermal project costs from the FY 2009 forecast, pending outcome of the current arbitration process, which should conclude later this summer.
- Examine extending Columbia Generating Station debt to the end of the current license period in 2024. Further discussion with customers and the Energy Northwest Board will be held on this topic. This is estimated to reduce FY 2007-2009 costs by roughly $30 million per year, but would increase out year costs.
- Continue the Enterprise Process Improvement Project and other internal cost control initiatives.
- Further examine the timing for spill tests on the Snake River in relationship to installation of surface passage technologies such as removable spillway weirs, while continuing to ensure that our Endangered Species Act commitments are met.
- Re-examine the recovery period for conservation capital (5 years will be used for the initial power rate proposal) based on progress defining long-term conservation programs in the Long-Term Regional Dialogue process and other capital considerations.

There are also cost increases that could become apparent before the final power rate proposal. These include:

- A proposed reduction of $1.5 million per year in funding for WECC/NERC compliance is included in the forecast. The final study of this program will be completed at the end of June indicating whether or not we can achieve this savings.
- Congress is currently considering legislation that would provide the Spokane Tribe with benefits similar to those received by the Colville Tribe to compensate for the loss of land resulting from Federal dam construction.
- The Corps of Engineers will decide when to begin treating funds for the Columbia River Fish Mitigation project as plant-in-service. This decision could increase FY 2007-2009 costs.

BPA will seek comment early next year on these further cost changes, prior to incorporating them in the final power rate proposal.

Some of the issues from the PFR are not being closed out at this time, as they will be finalized in the power rate case process. Risk mitigation packages and tools, along with debt management issues, will be discussed in the upcoming FY 2007-2009 power rate case. Additional information on the upcoming rate case is available on the BPA Web site at www.bpa.gov/power/ratecase.

Thank you very much for your attention and input to the Power Function Review. Your participation has made a difference. For further information on the PFR or other issues, please contact your customer account executive, constituent account executive, tribal account executive, or me at (503) 230-5399. The final PFR report and additional information on the process is available at www.bpa.gov/power/review.

Sincerely,

Paul E. Norman
Senior Vice President
Power Business Line

Enclosure:
June 24, 2005 - Power Function Review Final Report

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Bonneville Power Administration

Power Business Line's
Power Function Review Final Report
June 24, 2005

BONNEVILLE
POWER ADMINISTRATION

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Power Function Review Final Report

After a large BPA power rate increase in 2002 and ongoing scrutiny and reduction to many program levels, the level of interest from customers, constituents, and tribes in the costs that go into BPA's power rates is higher than ever. In response, and consistent with BPA's desire to increase the transparency of decisions that affect rates, BPA kicked off the Power Function Review (PFR) in January 2005 to examine the power cost forecasts for fiscal years (FY) 2007-2009 rate period prior to the start of the rate case. Throughout this process, BPA held numerous workshops to share information and listen to participants' ideas and comments on the nine major cost areas addressed in this process.

In May 2005, BPA issued a draft report with proposed program cost levels and solicited feedback on those levels. Participants dedicated many hours to this process, and BPA would like to thank those participants for the commitment and feedback they have provided. This report addresses the comments received and lays out BPA's final decisions in regard to the FY 2007-2009 program expense forecasts that will go into the power rate case initial proposal. As noted in the cover letter that accompanies this report, many of these areas will be revisited when more information is known before the rates are finalized in the summer of 2006. BPA will hold discussions separately from the rate case proceedings to share the updated forecasts and solicit feedback.

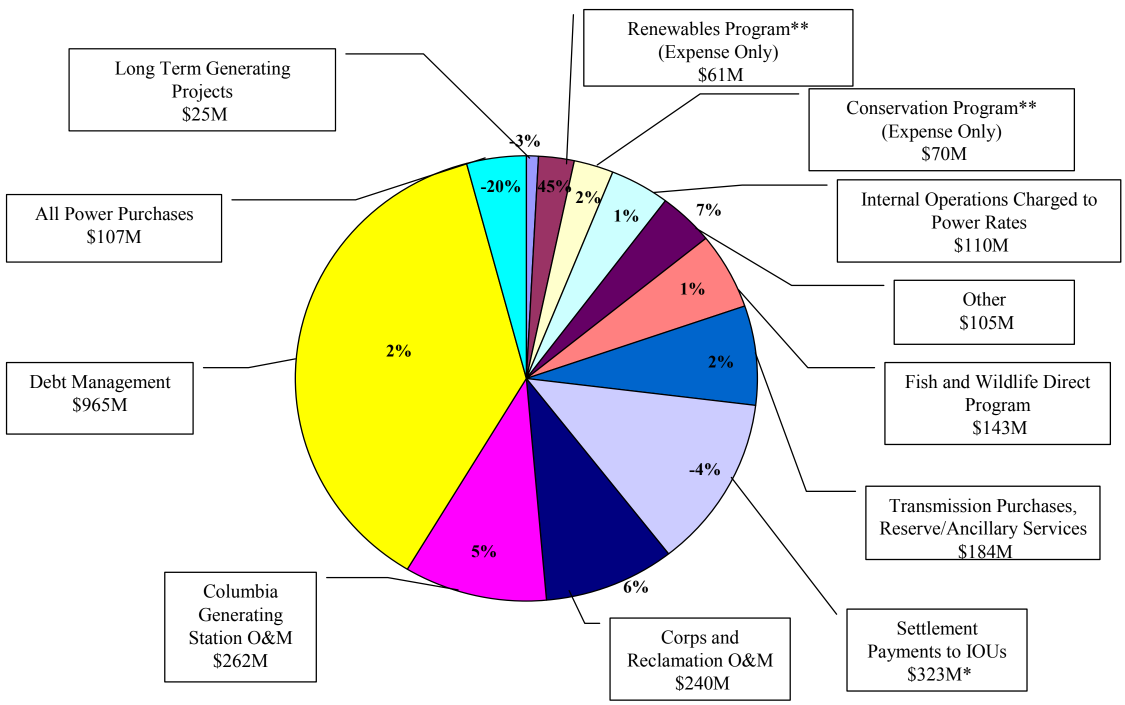
When the PFR began, many participants in the region were surprised to learn that FY 2007-2009 power rates were not expected to drop back to levels seen prior to FY 2002. Even though the total expenses for FY 2007-2009 are lower than in the current rate period, they are not as low as they were in the FY 1997-2001 period for many reasons that were explained throughout the PFR. One main reason is the increase in benefits BPA will provide the region in the FY 2007-2009 relative to the FY 1996-2001 period.

The average growth rates in many of the major program areas in the draft report have not increased significantly but have been fairly steady from the current rate period to the next (see Chart 1). It is also important to note that in the case of Conservation, Renewables and Long-Term Generating Projects, these programs provide offsetting revenues that are not shown so an increase or decrease in their expense forecast does not indicate the ultimate impact they have on power rates.

Chart 1:

FY 2007–2009 Power Expense Forecast

Totals and annual growth rates



*Total includes 900 aMW of Monetary Benefit ($139 M/yr average), and approximately 618 aMW of load augmentation (BPA power buyback) ($235 M/yr average)

**Does not include revenues from aMWs sold.

In response to the comments received on the draft report, BPA has made some modifications to its May 2 report for FY 2007-2009 expenses. These changes include the following:

- not adopting the proposed reduction to the Conservation Program of $5 million per year;
- revising the Renewables forecast for Calpine;
- updating the wind forecasting methodology; and
- revising slightly the Columbia Generating Station (CGS) forecast to include a change in the decommissioning trust fund contribution.

Many of the forecasts in the draft report were not modified as a result of additional comment, but will be re-evaluated prior to the final power rate proposal in 2006.

In summary, BPA proposed cost reductions totaling $80 million a year in the May PFR draft report. This has increased to $96 million a year in reductions in the final report. However, most of this $16 million additional reduction is due to a revised renewables forecast that also resulted in less energy production. Summary Table 1 provides the change in the expense forecasts from the beginning of the PFR process, the draft report and the final report.

Summary Table 1:

		PFR Base FY 2007-2009 Average Expense	PFR Base FY 2007-2009 Average Capital	PFR Draft Closeout Letter Average Expense	PFR Draft Closeout Letter Average Capital	PFR Final Report Average Expense	PFR Final Report Average Capital	PFR Delta Base to Final Expense	PFR Delta Base to Final Capital
1	Long-Term Generating Projects	$ 25	$ -	$ 25	$ -	$ 25	$ -	$ -	$ -
2	Renewables Program (Expense Only)	$ 56	$ -	$ 61	$ -	$ 42	$ -	$ (13)	$ -
3	Conservation Program (Expense Only)	$ 71	$ 32	$ 70	$ 28	$ 71	$ 32	$ -	$ -
4	Internal Operations Charged to Power Rates	$ 116	$ -	$ 110	$ -	$ 110	$ -	$ (6)	$ -
5	Other	$ 120	$ -	$ 105	$ -	$ 105	$ -	$ (15)	$ -
6	Fish & Wildlife Direct Program (Integrated Program)	$ 139	$ 36	$ 143	$ 36	$ 143	$ 36	$ 4	$ -
7	Transmission Purchases, and Reserve/Ancillary Services	$ 189	$ -	$ 184	$ -	$ 184	$ -	$ (5)	$ -
8	Settlement Payments to Residential & Small Farm Consumers of IOUs 1/	$ 323	$ -	$ 323	$ -	$ 323	$ -	$ -	$ -
9	Corps and Reclamation O&M for Hydro Projects	$ 242	$ 138	$ 240	$ 138	$ 240	$ 138	$ (2)	$ -
10	Columbia Generating Station O&M for Nuclear Plant	$ 284	$ -	$ 262	$ -	$ 263	$ -	$ (21)	$ -
11	Debt Management	$ 1,003	$ -	$ 965	$ -	$ 965	$ -	$ (38)	$ -
12	Power Purchases	$ 107	$ -	$ 107	$ -	$ 107	$ -	$ -	$ -
13	**Total**	**$ 2,674**	**$ 206**	**$ 2,594**	**$ 202**	**$ 2,577**	**$ 206**	**$ (96)**	**$ -**

1/ Total includes 900 aMW of Monetary Benefit ($139 M/yr average), and approximately 618 aMW of load augmentation (BPA power buyback) ($235 M/yr average)

2/ Total includes net impact of CGS capital decision. Final rate case outcome will show a reduction in CGS O&M and an increase in Debt Management.

The rest of this report takes each of the program areas and describes the recommendations made in the draft report, comments received, and any changes between the draft and final report.

TRANSMISSION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Transmission Purchases, and Reserve/Ancillary Services	$171 M/yr	$0 M/yr
FY 2007-2009 PFR Base Forecast	$189 M/yr	$0 M/yr
FY 2007-2009 Proposed PFR Forecast	$184 M/yr	$0 M/yr
FY 2007-2009 Final PFR Forecast	**$184 M/yr**	**$0 M/yr**

MAY 2 DRAFT REPORT:
The Transmission Acquisition Program represents costs associated with services necessary to deliver energy from resources to markets and loads. These costs include: transmission, ancillary services, real power losses, generation integration costs associated with the U.S. Army Corps of Engineers and Bureau of Reclamation transmission facilities, and metering and communication requirements.

The Transmission and Ancillary Service component represents costs associated with payments to BPA's Transmission Business Line for transmission and ancillary services associated with surplus sales. The goal of the BPA PBL transmission strategy is to determine the least-cost mixture of long-term and short-term transmission products that can meet the needs of PBL's surplus marketing strategy.

Possible Decreases Identified

1. **Proposal: Model the transmission expense associated with secondary energy at the minimum expense across the 3000 secondary energy scenarios rather than the average of 3000 secondary energy scenarios** – This is an issue to be decided in the rate case. BPA's intention is to keep a consistent treatment of secondary sales and transmission costs. Counting transmission costs associated with critical water but crediting rates with sales from average water would understate the expense associated with transmission for the sales from average water. **Draft Conclusion: No change in modeling of transmission expense.**

2. **Proposal: Reduce forecast for Metering/Telemetry/Equipment Replacement** - The metering, communications and TBL Engineering support component represents costs associated with the installation of metering, telemetry, communications equipment & replacements and ongoing charges to meet increasing PBL business requirements for frequency and granularity of meter data. In the PFR forecast there was $1 million per year spending level for equipment associated with forecasted future data needs. We have learned that in the future when this happens TBL will acquire the equipment and capitalize it so there is not a need to forecast for these costs in PBL anymore. There will continue to be ongoing costs associated with communications, which are expected to remain in the PBL expense forecast. Therefore, BPA concludes the Telemetry/Equipment replacement forecast should be reduced from $1 million per year to $200,000 per year. **Draft Conclusion: Remove metering/telemetry costs of $800 thousand per year.**

3. **Proposal: Reduce 3rd Party GTA Wheeling Forecast –** Revise the forecast for 3rd Party GTA Wheeling because when preparing the forecast there was an error in the formula when calculating the costs for the South Idaho OATT. The formula was double counting the expenses twice and then adding the inflation rate. **Draft Conclusion: Include update to reduce forecast by $4 million per year.**

MAY 2 DRAFT REPORT CONTINUED:

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Remove Metering/Telemetry Costs	($0.8 M/year)
Updated 3rd Party GTA Wheeling Forecast	($4 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Hold an open discussion in the rate case process regarding using increased TBL revenues from PBL secondary sales, including but not limited to Treasury repayment.
- Capture the appropriate mix of short and long-term transmission services needed for secondary sales; remain active in TBL forums and verify forecasting used to estimate costs of third-party transmission.
- Think seriously before placing transmission into another agency [like Grid West] where you will not have direct control of costs.
- Lower costs of transmission acquisition - if BPA incurs costs for special generation or load requirements, specific costs should be borne by that customer or generator.
- Budget transmission spending at the lowest level. Additional costs for secondary energy should be a deduction to surplus sales.

Final Report Decisions

One issue raised was that of modeling transmission expenses associated with the full distribution of secondary sales rather than modeling an average transmission expense. In other words, in years of below-average water, the transmission purchases associated with the secondary sales of that water would be less, and vice versa in above-average years. BPA agrees with customers and plans to model this variability in the rate case, which it has not done in the past. BPA is very focused on capturing the appropriate mix of short- and long-term transmission services needed for secondary sales. Therefore, PBL will stay active in TBL forums, and verify forecasting used to estimate costs of third-party transmission. With respect to the comment of Grid West participation, BPA will continue to review the costs and benefits of Grid West participation.

For now, BPA believes the forecast that was proposed in the draft report of $184 million per year on average remains the most accurate, but will incorporate the customer-recommended risk analysis in the appropriate studies of the 2007 power rate case. The Transmission Acquisition expense forecast (associated with secondary sales) will be updated with the secondary sales forecast used in the FY 2007-2009 power rate case.

CONSERVATION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Conservation Program (including rate credit)	$66 M/yr	$27 M/yr
FY 2007-2009 PFR Base Forecast	$71 M/yr	$32 M/yr
FY 2007-2009 Proposed PFR Forecast	$70 M/yr	$28 M/yr
FY 2007-2009 Final PFR Forecast	**$71 M/yr**	**$32 M/yr**

MAY 2 DRAFT REPORT:
The portfolio of energy efficiency programs BPA is proposing for the post-2006 period is very similar to what is currently available. BPA relied heavily on the Post-2006 Conservation Workgroup's recommendations in designing its proposed program approach. The key features of the proposed program are as follows:

1. a **rate credit program** (similar to the current C&RD with key changes, such as paying for only cost-effective measures, BPA incentives based on a % of what it costs to install measures and not value to the system, and requiring that measures be incremental, measurable, and verifiable with appropriate oversight and more frequent reporting);
2. a **bi-lateral contracts program** for our utility and federal agency customers (similar to the current ConAug program);
3. a **3rd party bi-lateral contracts program** for cost-efficient, region-wide approaches (similar to the VendingMi$er program and includes BPA's support for the NEEA);
4. support of critical **infrastructure** elements, especially evaluations so we know if we are getting what we are paying for;
5. a separately funded **renewable resource option**; and
6. a proposed spending amount of **$75 million/year** to capture BPA's 52 aMW per year share of the Northwest Power and Conservation Council's (Council) regional cost-effective conservation target at an overall cost of **$1.4 million/aMW.**

Through the PFR process, several areas where decisions are yet to be made were identified as either potential savings or increases to the Conservation spending level from the PFR base. Each of these areas were discussed and taken into consideration when developing the proposed FY 2007-2009 Conservation forecast.

Possible Decreases Identified

1. **Proposal: Credit conservation done by utilities "on their own nickel" against BPA's target, reducing BPA's spending** – BPA's conservation target is based on cost effective conservation as defined in the Council's 5th Power Plan and reflects only loads BPA serves. Also, BPA serves only a fraction of some public utilities' loads. BPA agrees that if those utilities are effectively meeting some of BPA' target through their own non-BPA-funded programs, then BPA should not separately forecast for the same conservation MWs. BPA does not believe that currently there is enough information on how much cost-effective conservation public utilities are accomplishing on their own to warrant forecasting a reduction now. However, BPA will track this going forward and adjust its forecast accordingly. If this can be done before final studies are done for the FY 2007-2009 rate period, this adjustment will be made before the final rate decisions are made. **Draft Conclusion: Do not include this reduction in Initial Rate Proposal, but possibly include it in final rate studies.**

2. **Proposal: Reduce BPA target for "naturally occurring" conservation** – BPA originally set the target at 40 percent, which is roughly the percent of the regional load BPA serves (7,782/20,472 aMW= 38 percent based on FY 2003 White Book information). This calculation is fully consistent with the methodology for setting conservation targets in this FY 2002-2006 period, as agreed to between BPA and the Council. After

MAY 2 DRAFT REPORT CONTINUED:

consultation with the Council's staff, BPA estimated which specific measures are likely to become standard practice in absence of any BPA/utility conservation programs. Based on this analysis, BPA estimated that roughly 7percent of the Council's targets would be naturally occurring. Seven percent equates to roughly 4 aMW out of BPA's 56 aMW annual target. Based on the loads BPA serves, our share of the Council's regional target over the FY 2007-2009 period is 168 aMW (40 percent of 420 aMW). This equates to an annual target of 56 aMW. We anticipate that the "naturally occurring" conservation will come in at about 7 percent or 4 aMW per year. This would give us a 52 aMW per year target and a 156 aMW target over the 2007-2009 period. While there has been some comment that the Council has set too high a target for conservation, BPA believes it appropriate and achievable. The Council conducted an extensive public process as conservation potential was analyzed, and BPA and many others in the region participated in that process. Thus, BPA concludes the 52 aMW per year is the right target. **Draft Conclusion: Include $4 million annual capital and $1 million annual expense reductions in the Initial Rate Proposal.**

3. **Proposal: Don't require load decrement on rate credit** – PFR participants commented that it will be harder for BPA to meet its MW targets for conservation within its spending level limit if it requires block and slice customers to reduce their load on BPA by the amount of conservation they accomplish under the conservation rate discount program. Consistent with the advice of its Post-2006 Conservation Workgroup, BPA has now proposed not to require load decrements from slice/block customers under the rate credit program, but continuing to require load decrements under the new bi-lateral contract program. **Draft Conclusion: Make the change recommended, but no reduction in costs.**

Possible Increases Identified

1. **Proposal: Do not count IOU conservation BPA pays for toward BPA's target, or count these MW's but also add IOU residential conservation to BPA's target** – BPA proposes to count toward the 52 aMW annual target any cost effective conservation it helps ensure through its funding mechanisms, including the conservation achieved by IOUs under the rate credit program and the conservation accomplished by our Northwest Energy Efficiency Alliance (NEEA) funds. This decision is consistent with the current way we count delivered savings toward our share of the Council's target in the rate period as agreed to by Council staff. Further, BPA invests in regional conservation that is currently counted toward BPA targets, e.g., NEEA market transformation. Counting conservation funded by IOU rate credits is fully consistent with the methodology we use in this rate period, and should be extended to the FY 2007-2009 rate period. If BPA pays for it, BPA should count it toward our targets. **Draft Conclusion: Count IOU MW's and add to target, but no cost increase.**

2. **Proposal: Increase spending to increase certainty of meeting conservation targets** – BPA acknowledges that the $1.4 million per aMW target is a stretch. Based on recent conservation program performance and given the changes that have been made in the designs of the proposed program portfolio, BPA believes it has a reasonable chance to achieve its share of the Council's new conservation aMW targets with the proposed spending level. It is important to note that while BPA is targeting $1.4 million per aMW, that figure is an average of different program spending levels. BPA has been successful at lowering the cost of savings through the Con Aug Program, and BPA will seek to continue to average program costs in the revised bilateral contracts at the current level ($1.2 million per aMW). Similarly, NEEA has a demonstrated track record of $1 million per aMW. This leaves the budgets for local initiatives higher ($1.7 million per aMW). Thus, the success to date with driving down program costs and continuing to adapt new marketing strategies leads BPA to believe these forecasted targets are achievable. Just as important, BPA believes that setting and meeting aggressive cost containment goals is important both to keep rates down and to maintain support for steady conservation funding, since higher costs per MW make conservation spending levels less sustainable during periods of even greater financial stress. BPA will assess progress towards our aMW conservation goal and proposes to adjust for underperformance against the target in the next rate period. **Draft Conclusion: Keep funding at current forecast.**

3. **Proposal: Increase spending level for administrative costs** – BPA is proposing to pay up to 10 percent of administration costs under the new rate credit and bilateral contracts program. The Conservation

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Workgroup recommended 20 percent of administrative costs be included. The current C&RD credit allows credit of 20 percent for administration cost to support infrastructure building. For ongoing conservation programs, however, administration should be lower. A number of utilities and end users that are partners in capturing the regional conservation have told BPA they don't need a full 20 percent administration for on-going programs. BPA has included a number of activities and tools that should reduce utility administration costs (e.g., standard program design templates and marketing materials, mechanism for utility sharing, etc.). However, BPA received numerous written comments on this topic shortly before issuing this report and will consider them during the comment period. **Draft Conclusion: Keep funding at current forecast.**

4. **Proposal: Increase spending level for conservation infrastructure** – The Conservation Workgroup recommended a 2 percent infrastructure spending level (i.e., $1.6 million per year). BPA has proposed instead conservation spending levels for FY 2007-2009 that includes $1 million per year for the infrastructure spending that should be sufficient to cover these activities. The 2 percent infrastructure support forecast was not based upon detailed analysis and budgeting. More detailed analysis developed by BPA leads the Agency to conclude the necessary infrastructure support can be accomplished at the $1 million per year level. The $1 million per year is a component of the $75 million per year proposed conservation acquisition program level. **Draft Conclusion: Keep funding at current forecast.**

Table 1: Proposed Conservation Program Annual aMW Targets and Spending Levels

Program	aMW	Forecast	Cost/aMW
Rate Credit (at 0.5 mills = $42M*/year with IOUs and Pre-Subers included)	21	$36M	$1.7M
Utility & Fed. Agency Bi-Lateral Contracts	15	$21M	$1.4M
3rd Party Bi-lateral Contracts	6	$7M	$1.2M
Market Transformation (via NEEA)	10	$10M	$1.0M
Infrastructure Support and Evaluation	---	$1M	---
Total	52	$75M	$1.4M

* - *assumes $6 million per year of the $42 million per conservation rate credit will be spent on renewables .*

In total, BPA proposes to reduce the base PFR spending levels (both capital and expense) for achieving the Council's cost-effective conservation target by $5 million per year to $75 million per year (includes the conservation rate credit), which is a portion of the overall Conservation forecast of capital and expense spending. The proposed spending level is an actual increase of $5 million per year over the average annual spending level in the current rate period.

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Table 2: PBL Total Proposed Conservation Forecast FY 2007-2009

Program	Proposed Forecast	Annual MW Target Spending
Generation Conservation Expenses	**$34.0 M**	
EE Development (Reimbursable)	$12.9 M	
Energy Web/Non-Wires Solutions	$1.0 M	
Technology Leadership	$1.3 M	
Legacy (Contract closeout after FY 2000)	$2.8 M	
Low-Income Weatherization	$5.0 M	
Market Transformation	$10.0 M	YES
Infrastructure Support and Evaluation	$1.0 M	YES
Conservation Rate Credit	**$36.0 M**	**YES**
Expense Total	**$70.0 M**	
Generation Conservation Capital Total	**$28.0 M**	
Utility & Fed Agency Bi-Lateral Contracts	$21.0 M	YES
3rd Party Bi-lateral Contracts	$7.0 M	YES

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Reduce Conservation Expense Spending Level	($1 M/year)
Reduce Conservation Capital Spending Level	($4 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Revisit the amortization period for Conservation Augmentation.
- Ramp up to meet additional conservation in next two years. Have a backstop in case the plan fails to meet target.
- Credit money generated by conservation against program costs.
- Resolve cost-effective measures and other issues before setting a conservation target.
- Carefully consider treatment of the rate credit.
- Continue to link conservation/renewables in discount program.
- BPA should get credit if utilities are doing conservation beyond BPA program; BPA program would accomplish more if utilities did not have to worry about decrement.
- Changes that would centralize the conservation program are unwelcome.
- If BPA money is being spent in an IOU service territory, it should count toward BPA target.

- Significantly increase investment in energy efficiency. Invest up to $150 million per year and acquire 70 to 80 aMW.
- BPA should not count IOU conservation accomplishments toward its target; decrementing raises the cost of conservation for utilities.
- BPA's conservation target should be 70 aMW, not 52; if you decrement, you should credit revenues from resources you sell toward conservation program. The funding level is too low to meet the target. A more realistic budget would be $133 million to achieve 70 aMW.
- Naturally occurring conservation should count toward BPA goal.
- BPA should back away from the commitment to meeting the Council targets.
- Raise your rates immediately to pay off more debt and promote more renewable energy programs.
- Restore the $5 million cut in the course of PFR. Add funds to increase the probability of meeting targets set. Include a contingency plan in case BPA and utilities fall short of meeting the target.
- No additional budget above $75 million for conservation unless there are robust measures that would work for all utilities. Budget is meaningless without a realistic target and measures that work.
- Design a conservation program that works for all customers; as designed, the program is unfair to some customers.
- One size does not fit all with conservation; provide flexibility for customers in different areas to capture potential.

Final Report Decisions

In the draft report, BPA proposed reducing the conservation forecast needed to acquire BPA's share of the Northwest Power and Conservation Council's (Council) new conservation targets by $5 million/year for the 2007-2009 power rate period. The original forecast was $80 million per year needed to capture the 56 aMW per year target. BPA felt that about 7 percent of this target was "naturally occurring" conservation that BPA, or anyone, should not need to fund. This reduced the target from 56 aMW per year to 52 aMW per year and, accordingly, the expense forecast BPA proposed to achieve the target.

In a parallel process, BPA developed and issued for public review and comment a post-2006 Conservation Program Proposal, including the PFR conservation forecast information. Table 1 provides a detailed breakdown of how the proposed $75 million per year forecast would be allocated across the portfolio of proposed conservation programs. Table 2 shows the total proposed conservation forecast for FY 2007-2009.

Many of the issues raised in the PFR comment periods are more properly addressed under the post-2006 Conservation Program process. Documents presenting BPA's final decisions on those issues will be available on BPA's energy efficiency Web site soon. With regard to the conservation forecast for FY 2007-2009, BPA has decided to return to the original $80 millon per year forecast to provide a greater confidence that it will capture the 52 aMW per year target, and to respond to customer and other comments on administrative costs and other issues. The rationale for this decision is further detailed in BPA's separate document on post-2006 conservation decisions. Table 3 provides a detailed breakdown of how these funds will be allocated across the final program portfolio. BPA also received comments regarding the need to focus on irrigation efficiency improvements to both reduce energy consumption and reduce water use. BPA has under development or recently launched several initiatives to pursue irrigation efficiency. A scientific irrigation scheduling pilot demonstration project was recently launched. A pump testing initiative is scheduled for launch in the early summer of 2005 with a companion rebate/standard offer program targeted at irrigation efficiency measures (the companion program was launched in June 2005 resulting in two customer utility contracts immediately).

Table 3: Final Conservation Program Annual aMW Targets and Budgets

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

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

Table 4 provides the final PBL total conservation forecast for FY 2007-2009.

Table 4: Final PBL Total Conservation Forecast FY 2007-2009

Program	Final Forecast	Annual MW Target Spending
Generation Conservation Expenses	**$34.0 M**	
EE Development (Reimbursable)	$12.9 M	
Energy Web/Non-Wires Solutions	$1.0 M	
Technology Leadership	$1.3 M	
Legacy (Contract closeout after FY 2000)	$2.8 M	
Low-Income Weatherization	$5.0 M	
Bi-Lateral Contract Activity	$1.0 M	YES
Market Transformation	$10.0 M	YES
Infrastructure Support and Evaluation	$1.0 M	YES
Conservation Rate Credit	**$36.0 M**	**YES**
Expense Total	**$71.0 M**	
Generation Conservation Capital Total	**$32.0 M**	
Utility & Fed Agency Bi-Lateral Contracts	$25.0 M	YES
Third Party Bilateral Contracts	$7.0 M	YES

RENEWABLES PROGRAM

	Average Expense	*Average Net Cost**	Average Capital
FY 2002-2006 Renewable Program	$22 M/yr	*$2 M/yr*	$0 M/yr
FY 2007-2009 PFR Base Forecast	$56 M/yr	*$13 M/yr*	$0 M/yr
FY 2007-2009 Proposed PFR Forecast** *w/o Rate Credit*	$61 M/yr *$55 M/yr*	*$15 M/yr* *$9 M/yr*	$0 M/yr *$0 M/yr*
FY 2007-2009 Final PFR Forecast** *w/o Rate Credit*	**$43 M/yr** *$37 M/yr*	***$16 M/yr*** *$10 M/yr*	**$0 M/yr** *$0 M/yr*

**Takes the Average Expense column and subtracts the estimate of revenues from the renewables program.*
***Includes Renewable rate credit of $6M/year in Average Expense. Previous forecasts did not.*

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BPA began funding renewable-related research nearly 30 years ago through solar monitoring, a wind demonstration project, geothermal and wind resource assessments, and a range of projects across other technologies, many in cooperation with other sponsors. As part of the Short-Term Regional Dialogue process, BPA decided in February 2005 to focus on facilitation of regional renewable resources by its customers and others, and to limit its financial contribution to a net cost of $21 million per year. BPA has identified a menu of facilitation actions and is consulting with a regional workgroup on which of those actions will maximize the amount of renewable resource development, within BPA's financial contribution limit. This group has advocated, and BPA agrees, continuing to include renewables in the utility actions eligible for the rate discount program for FY 2007-2009 at the level of $6 million per year. This leaves much of the $21 million annual net cost limit uncommitted due to higher long range market price forecasts that produce a break even cost for existing renewable contracts (the room under the target will vary as long range market price forecasts change). Rather than simply assume the entire $21 million level is spent, BPA intends to include the best estimate of actual spending in the rate case cost forecasts. This was the basis of the PFR base case cost levels.

Through the PFR process, participants have identified several areas that would both increase and decrease portions of the FY 2007-2009 renewables spending level forecasts.

Possible Decreases Identified

1. **Proposal: Remove the Calpine geothermal project from projected costs** – The assumption in the PFR base is that the Calpine project comes on line in FY 2007 and operates during the rate period. The Calpine contract is currently in arbitration and a decision is not expected to come until late summer. Some PFR participants urged that BPA assume that it will not have to purchase the high-cost output of this project, or that its online date will be significantly delayed. BPA believes that it is highly unlikely that it would be purchasing output from this project any sooner than FY 2009, even if BPA loses in the ongoing arbitration process. Therefore, BPA is proposing to move the forecast of the geothermal out of FY 2007 and FY 2008 but leave it in the forecast for FY 2009 for the initial power rate proposal. BPA does not believe the project costs should be removed entirely until the outcome of the arbitration is known. This forecast will be revised in time for the final rate proposal after the arbitration decisions have come about late this summer.
Draft Conclusion: Remove geothermal project costs in FY 2007 and 2008.

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2. **Proposal: No further renewable spending beyond what is already contractually committed** – This option was not actually advocated by PFR participants, but was included by BPA as a "bookend" for discussion. Having recently decided on the $21 million limit after an extensive public process, BPA does not believe it is appropriate to now "zero out" its renewable resource support. **Draft Conclusion: Do not "zero out" incremental renewable resource facilitation.**

Possible Increases Identified

1. **Proposal: Add facilitation forecast for FY 2007-2009 if Calpine is taken out of the forecast** – BPA remains committed to facilitating customer renewable acquisitions and recognizes it's role in helping the region meet renewable targets. Removal of the Calpine geothermal project allows other facilitation actions to be added without exceeding the $21 million annual net cost limit. Some PFR participants and Renewable Workgroup members supported this. Others also recommended that the facilitation spending estimate be revisited annually in consultation with customers and together they would jointly assess the need for facilitation spending. BPA agrees that its rate proposal costs should include reasonably foreseeable renewable facilitation costs, but not simply "placeholder" dollars up to the $21 million limit. BPA believes the best estimate of this is $5.5 million in FY 2007 and $11 million in FY 2008. This estimate will be updated before final rate studies are done in consultation with customers. **Draft Conclusion: Include $5.5 million in FY 2007 and $11 million in FY 2008 for renewable facilitation actions.**

2. **Proposal: Include a Renewable Rate Credit** – The current rate period combines the renewable and conservation rate credit into one lump sum. Through the Conservation and Renewables Workgroups it has been proposed to separate this credit into distinct categories. BPA also heard the desire to give customers the option of committing for one year at a time rather than for all three years at once. The PFR base forecast did not have the renewable rate credit embedded. **Draft Conclusion: Include the $6 million per year rate credit.**

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Remove forecast of Calpine from FY 2007-2008	($11 M/year for FY07-08)
Include facilitation forecast for FY 2007-2008	$8 M/year for FY07-08
Include renewable rate credit	$6 M/year

Summary of Comments Received on Proposed PFR Forecast

- Take Four Mile Hill out of the projection for FY 2007-2009.
- BPA transmission policies for renewables are leading the nation.
- Renewables need consistent funding.
- Provide money up front to help developers get renewables projects under way.
- BPA can play a critical role in helping to deliver renewables in the region through transmission and integration, promoting promising technologies, and facilitating partnerships. Strategically target upgrades to transmission to open up development.
- BPA should maintain leadership role with renewables; continue facilitation with a $21 million investment over the rate period; continue $6 million for renewable in the rate discount; and an additional $15 million for renewables facilitation is prudent.
- BPA should continue leadership on renewable energy, provide continuity and continue to facilitate, follow through on existing commitments, define programs for customers that will provide incentives for new renewable energy acquisition and help customers

overcome unique barriers, provide new funding rather than use leftover funds from previous rate period, and continue to identify good acquisition opportunities. Budget for facilitation should be $15 million per year, and we reject $5.5 million (FY 2007) and $11 million (FY 2008) proposal.

- Cannot support construct for renewables, which creates an unclear revenue requirement, is selective conditional budgeting, perpetuates disconnect between BPA's avoided costs and other activities, provides favorable treatment to renewables versus conservation.
- Fund renewables fully in next two fiscal years. Oregon has adopted a renewables action plan and BPA could help to achieve it if it would fund grants and upgrades to distribution facilities that make more renewable projects possible.
- Cannot support "facilitation" cost placeholders in revenue requirement.
- Include money for facilitation only if BPA has above average secondary revenues.

Final Report Decisions

In the recent Record of Decision (ROD) on the Short-Term Regional Dialogue, BPA decided to accept a net cost of up to $21 million per year for renewable resource facilitation. BPA agrees with comments that it should stand behind this commitment, and that it should limit expenses covered by power rates for unidentified renewable projects. BPA agrees with the facilitation funding level set by the Renewables Workgroup as it strikes the right balance of these two interests. BPA will continue working with this group to better define these facilitation actions and their costs. However the question of using premium revenues from EPP, ARE, renewable attributes sales was also raised in the comment period. BPA is committed to devoting those revenues to renewable projects. Therefore BPA's conclusion is that $5.5 million in FY 2007 and $11 million in FY 2008 should be committed to renewable facilitation, in addition to all premium revenues from sales of EPP, ARE, and tags/renewable energy certificates. The latter revenues are estimated at $1 million in FY 2007 and $1 million in FY 2008, but could be higher or lower depending on actual sales.

In the course of the PFR draft report, it was noticed that the reductions in the renewable forecast due to removing Calpine in FY 2007-2008 were misstated. The net costs were removed instead of the gross costs. Making this correction reduced the renewables forecast by an additional $14 million per year on average (draft report had $7 million per year savings on average and it should have been $21 million per year on average).

Another area that changed from the draft report was the wind power purchase costs. BPA has historically based forecasted wind power costs on estimated capacity factors provided by project developers at the time the power purchase agreements were signed. Actual wind generation over the last 3 years has proven to be less than originally estimated. We are revising the wind project costs downward in FY 2007-2009 by $4 million per year to reflect our wind projects' historical generation profile, but are not capping wind power costs at the reduced level because actual generation, operation and maintenance costs vary from year to year.

BPA will revisit whether or not to include Four Mile Hill generation costs in the FY 2009 forecast in the final rate studies next spring, based on the outcome of the ongoing binding arbitration concerning that project.

INTERNAL OPERATIONS CHARGED TO POWER

	Average Expense	Average Capital
FY 2002-2006 Internal Operations Charged To Power Rates	$107 M/yr	$0 M/yr
FY 2007-2009 PFR Base Forecast	$116 M/yr	$0 M/yr
FY 2007-2009 Proposed PFR Forecast	$110 M/yr	$0 M/yr
FY 2007-2009 Final PFR Forecast	**$110 M/yr**	**$0 M/yr**

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This cost category is driven by BPA's strategic direction: "Effective cost management (with emphasis on best practices, innovation and simplicity) through our systems and processes." It includes BPA staffing costs, travel, training, consultant contracts, building leases, IT services, and other related costs. BPA has been managing these costs very actively over the last several years and has kept the rate of growth well below the rate of inflation over the last four years. Several actions are underway now to bring these costs down further, including agency-wide process reviews, reductions in high-graded positions, and consolidation of functions currently performed in both power and transmission business lines. The primary challenge for the PFR process is determining the level of savings to include from these ongoing efforts since they will not be finalized before the PFR process concludes in June. PFR participants urged BPA to include its best estimate of savings from these efforts in its PFR conclusions.

Possible Decreases Identified

1. **Proposal: Reduce monetary awards** – During the current rate period, BPA drastically reduced award budgets in response to the financial crisis the region faced. In the FY 2007-2009 base PFR forecasts BPA proposed to increase award budgets, but not to historic levels, and to tie them to financial standards, as they were in the past. If the financial standards are not met the awards are not paid out. This item was an area identified as a place to reduce the spending forecast in the PFR process. Advice from PFR participants was to keep the increased awards amounts but to make sure they are tied to financial performance standards. BPA agrees with this and proposes to maintain the amounts included in the base PFR forecast. **Draft Conclusion: No reduction in awards cost.**

2. **Proposal: Include forecast of savings from process improvement efforts** – As BPA is in the middle of process efficiency studies, many of the potential areas of possible reductions have not been fully studied and resulting savings quantified. Many customers, however, have voiced concern that these efficiencies will not be reflected in their FY 2007-2009 power rates unless savings are forecasted now. BPA agrees with this concern. As an interim target for inclusion in the initial power rate proposal, BPA proposes to reduce its total internal costs allocated to power rates in FY 2007-2009 to roughly the same amount spent on these functions in FY 2001, with no allowance for inflation. This is a reduction of $8 million per year from the PFR base. Given that BPA's responsibilities have increased and will continue increasing over this 8-year period, absorbing inflation in internal spending will require significant success in the ongoing efforts to improve internal processes along with reductions in staffing. Based on progress to date on these efforts, BPA is sufficiently confident in its ability to meet this target to include it in the initial rate proposal. Internal costs will be updated before the final rate studies are done in 2006. **Draft Conclusion: Reduce internal costs by $8 million per year to reflect process improvement efforts.**

Possible Increases Identified

1. **Proposal: Include but reduce spending level of uncommitted technological innovation spending (TCI)** – The mission of the Technology Confirmation / Innovation Program is to confirm the potential application of emerging technologies to BPA's enterprise to achieve BPA's strategic objectives more effectively and efficiently. Total TCI funding consists of the (1) base level of funding that is already

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incorporated into organizational forecasts and (2) incremental funding. The proposed funding in the Corporate G&A forecasts in the base PFR forecast is for incremental funding. BPA proposed to add to the base level of funding gradually, to yield a total TCI level that would be in the range of 0.3 percent - 0.5 percent of revenues by FY 2011. However, after listening to participants and customer concerns about adding additional costs to this rate period, but also understanding there is support for spending money on these efforts based on the belief that the electric industry is under-spending in this area and that the potential rewards from applied technologies can far exceed the development costs, BPA proposes to scale back but not eliminate incremental TCI funding. The resulting reduction in corporate TCI costs to $2.4 million per year (which translates to PBL costs of approximately $1.3 million per year) is a reduction of $400,000 per year from the corporate TCI PFR base. These numbers assume that both PBL and TBL undertake TCI-related actions over these years at levels that have been indicated in earlier discussions. For example, it is assumed that PBL will be picking up its half of the Bureau of Reclamation's hydro R&D expenses beginning in FY 2006 and that Energy Efficiency's TCI-related expenses will continue. **Draft Conclusion: Include the TCI forecast of $1.3 million per year in Internal Operations Charged to Power.**

TCI Program Proposal	**FY 2006**	**FY 2007**	**FY 2008**	**FY 2009**
PFR Base Total	0	0	0	0
PFR Workshop Total	$250	$1,500	$2,750	$4,100
Proposed PFR Total	**$ 500**	**$ 1,400**	**$ 2,400**	**$ 3,400**
PBL Share	*$ 250*	*$ 1,000*	*$ 1,200*	*$ 1,700*
TBL Share	*$ 250*	*$ 400*	*$ 1,200*	*$ 1,700*

BPA Proposals	**Proposed PFR Base FY 2007-2009 (Reductions)/Increases**
Include TCI forecast in Internal Operations Charged to Power	$1.3 M/year
Include process improvements in Internal Operations Charged to Power Forecast	($8 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Early outs and retirements are an opportunity to consider new ways to staff. Drive toward lower number of FTE in the next rate period.
- Align reward targets with a rate target and customer benefits.
- Roll back corporate spending on IT.
- Use 2 percent annual inflation going forward.
- Reallocate industry-restructuring costs.
- Adjust budget for power non-generation operations.
- Reduce Corporate G&A due to efficiencies from Enterprise Process Improvement Projects (EPIP).
- Reduce funding for Technology Confirmation/Innovation.
- Make line item budget and spending available on line for scrutiny of specific expenditures, such as travel, consultants, office space, etc.
- Vigorously pursue EPIP study.
- The industry has been under-investing in technology.

Final Report Decisions

In the PFR draft report, BPA proposed a reduction of $6 million in internal operating costs to be recovered in power rates, which left those costs at roughly the same level in FY 2009 as they were in FY 2001, with no allowance for inflation. This amount includes both PBL costs and all corporate costs allocated to power including IT and industry restructuring costs. BPA is able to include this additional reduction through stringent cost management. The number of employees has declined since 2001, and is expected to decline further. This cost level is consistent with virtually all the recommendations made in PFR comments. BPA internal operating costs, unlike CGS and other operational costs, are not growing to any significant extent despite increased requirements for security and other new or increased functions.

We are proud of this accomplishment. BPA continues to work actively on better managing these costs through the on-going EPIP and position management. The EPIP processes follow up on efficiency recommendations made by KEMA, Inc. in its study conducted earlier this year. The $8 million reduction proposed in the draft report is an early estimate of the savings achievable through the implementation of the EPIP studies currently underway, as well as future EPIP studies. Results foreseeable at this time make us confident we can reach this level of savings in internal operating costs allocated to power. As such, the initial power rate proposal will include this level of savings, consistent with the draft report recommendation, even though they are not these savings have yet to be achieved. This estimate of savings will be updated for the final power rate proposal to reflect the implementation plans of the current EPIP studies, as well as any preliminary estimates from future studies. We feel that the EPIP studies are the most promising way for BPA to address efficiencies in internal operating costs. These studies will point us toward greater efficiency in performing the work needed to successfully deliver our power, transmission and public responsibility obligations and mission.

HYDRO SYSTEM O&M AND CAPITAL INVESTMENTS: CORPS OF ENGINEERS AND BUREAU OF RECLAMATION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Corps and Reclamation	$196 M/yr	$110 M/yr
FY 2007-2009 PFR Base Forecast	$242 M/yr	$138 M/yr
FY 2007-2009 Proposed PFR Forecast	$240 M/yr	$138 M/yr
FY 2007-2009 Final PFR Forecast	**$240 M/yr**	**$138 M/yr**

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The Corps of Engineers (Corps) and Bureau of Reclamation (Bureau) operate and maintain the hydro system that produces around 90 percent of BPA's power under average water conditions. The age and conditions of the facilities under each of these organizations is different, resulting in different needs and proposed spending levels in the base PFR forecast. Through the Sounding Board process, the agencies recognized that they need to be able to succinctly explain the hydro program's resource requirements. In the PFR process we've presented detailed information about the asset management business model we operate the hydro system under, as well as very specific data used to determine the resource requirements that comprise the FY 2007-2009 forecasts. Because these forecasts are one of the larger components of costs that will make up the FY 2007-2009 rate: BPA, the Corps, and Bureau have worked very hard to develop spending levels that reflect minimum cost requirements while still meeting the systems operational, power generation and reliability requirements for the region. There was much concern about the increase from prior funding levels in the O&M and capital forecast from some PFR participants in the FY 2007-2009 timeframe. Much of this increase is due to the Corps and Reclamation adopting a long-term asset strategy for management of the hydro facilities, and to enable the Corps to shift from a mode of breakdown maintenance to preventive maintenance. The age of the hydro facilities is also playing a part in the O&M forecasts where extraordinary maintenance items are starting to occur at the same time that there are increased costs from security mandates. Even with these cost increases, Corps and Bureau costs are below industry O&M benchmark costs (excluding F&W costs). Even though there are many cost issues facing the Corps and Bureau such as aging facilities and increased security and F&W costs, the PFR was still able to identify a few areas to decrease the base PFR forecast by relatively small amounts. Additionally there are longer-term efforts to manage costs that may yield savings in the future and the agencies are willing to engage in focused benchmarking efforts against Mid-Columbia hydro projects owned by BPA customers.

Possible Decreases Identified

1. **Proposal: Reduction in funding for WECC/NERC compliance** – The PFR base includes a forecast needed for compliance requirements. Although the final review of our program to manage these requirements will not be completed until the end of June, preliminary results are indicating that compliance can be achieved for about $1.5 million less than the initial estimate. There is still some level of risk associated with this value; both in terms of the uncertainty until the review is complete and in terms of any new WECC/NERC requirements that are not forecasted. BPA believes this is an acceptable level of risk and proposes to include the $1.5 million per year savings in the PFR forecast with the ability to update that assumption in the final power rate proposal after the studies have been concluded. **Draft Conclusion: Include $1.5 million annual reduction.**

2. **Proposal: Reduce proposed level of funding for extraordinary maintenance** – There currently is a forecasted need of $18 million per year for extraordinary maintenance items in the FY 2007-2009 time period and beyond, but only $8 million per year is included in the base PFR forecast. Some of the participants in the PFR workshops questioned that spending appeared to continue to increase over time even though some of the lagging performance indicators show acceptable performance standards for some time periods. BPA is concerned about the age of the facilities and the power generation and revenue

MAY 2 DRAFT REPORT CONTINUED:

Impact if the spending for extraordinary maintenance items is eliminated, directly impacting system performance. BPA proposes to keep the $8 M/year in extraordinary maintenance costs, understanding there are more projects identified than funding available. The Corps, Bureau, and BPA will continue to use a step-up approach to the proposed extraordinary maintenance costs that specifically identifies the projects to be funded and their priority in terms of benefits to the system and dollar impacts. **Draft Conclusion: No reduction in costs for extraordinary maintenance.**

3. **Proposal: Eliminate discretionary overtime funding** – This category has small dollars attached to it but big impacts. The discretionary overtime forecast is designed to fund work that is needed in order to get a unit back in operation as soon as possible to help avoid lost revenue. BPA does not recommend eliminating this item due to concerns about impacts on unit availability and power generation. **Draft Conclusion: No elimination of forecast for discretionary overtime.**

4. **Proposal: Reduce costs of management of security requirements –** The Corps, Bureau, and BPA are working closely to be as efficient as possible in carrying out security responsibilities, but security requirements included in the base PFR are mandatory for the Corps and Reclamation. **Draft Conclusion: No reduction in security management costs.**

5. **Proposal: Benchmark against similar regional hydro facilities to capture efficiencies** – The Corps and Bureau have participated in industry benchmarking for the past four years along with other regional hydro facilities. One way to capture savings over time is to find more efficient ways to perform the work required. During the PFR workshops it was suggested that facilities with similar operations on the Mid-Columbia get together and share information on costs and ideas on efficiency gains. BPA, the Corps and Bureau embrace this proposal and intend to pursue it. BPA proposes that any savings from this effort be accounted for in the final power rate proposal after the project is underway and potential savings are identified. **Draft Conclusion: Engage in regional benchmarking and include savings estimates in final rate studies.**

6. **Proposal: Include efficiencies in staffing** – There are several opportunities for staffing savings over the next few years. The average age of employees at the Corps and Bureau is similar to that at BPA and both these organizations are expecting to see a high number of their workforce retire over the next few years. This provides an opportunity to replace this more senior workforce with new employees at lower grades and benefits. The Corps is also implementing a nation-wide program called 2012 designed to improve efficiencies within its organization, as well as performing a functional review across multiple areas and disciplines. Results from these types of programs will increase operational efficiencies in the future but it is too soon to estimate any savings in the FY 2007-2009 time period. **Draft Conclusion: Do not include a forecast of efficiencies in the initial power rate proposal but will be included in the final power rate proposal if any are identified.**

7. **Proposal: Include funding for remote operation of projects** – Currently, the Corps is studying the possibility of remotely operating Albeni Falls and Libby from the Chief Joseph project. The initial costs of this project are for installation of the hardware and the payback comes over time. The savings are in labor dollars and occur from a reduction in the number of operators at the facilities after the project is completed. This capital project is currently assumed in the base PFR capital forecast, but because it is a capital project, any savings from eliminating the initial capital cost has essentially no effect on PFR rates. Due to the payback nature of the project, BPA recommends including this project with the forecast of savings beginning to be realized after the FY 2007-2009 rate period. **Draft Conclusion: Pursue project with negligible impact on FY 2007-2009 costs.**

In summary, BPA proposes to decrease the Corps and Bureau FY 2007-2009 O&M expenses by $1.5 million per year. This results in an average FY 2007-2009 level of Corps and Bureau O&M expense forecast of approximately $240 million per year for the FY 2007-2009 time period. BPA does not propose any changes in the FY 2007-2009 forecasted capital spending level in the base PFR forecast which is on average $138 million per year.

MAY 2 DRAFT REPORT CONTINUED:

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Reduce funding for WECC/NERC compliance	($1.5 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Shift the drawdown at Grand Coulee for head gate repair to the fall.
- Set up a contingent financing fund for extraordinary hydro system maintenance.
- Don't place a hard cap on hydro O&M: some projects should be completed without crowding out others. The real emphasis should be on finding more cost-effective investments.
- Take the conservation and renewables budgets and direct them to hydro O&M.
- Increases for Corps and Bureau O&M are very large and unwarranted.
- We have a constrained transmission system in the region, and if we don't have sufficient generation, it could mean going outside for purchases.
- Include BPA customers' representatives on the Joint Operating Committee (JOC); develop better measures of success for O&M and capital programs; revise Asset Management Strategy.
- Keep up with capital programs on hydro system; a move from breakdown to preventive maintenance cuts costs.
- Work to prevent surprises like the $300 million in CRFM costs in the future.

Final Report Decisions

The final PFR FY 2007-2009 expense forecast level for Corps and Bureau hydro system O&M is $240 million per year. The capital spending forecast is an average of $138 million per year. The forecast levels are the same as the levels recommended in the May 2, 2005 PFR draft report. This reflects BPA's basic conclusion, detailed below, that cost cuts below this level would have too high of a likelihood of causing revenue losses through the loss of generation to forced outages and/or increases in costs to repair failed equipment that would more than equal the O&M cost savings. This conclusion will be further tested over the next eight months through head-to-head O&M benchmarking against Mid-Columbia and other regional hydro projects – an effort that was proposed by PFR participants and has been agreed-to by BPA, the Corps, Bureau, and Grant County PUD.

The range of comments submitted by stakeholders and customers was important in determining the final PRF forecast levels. Generally, the value of the hydro system to the region was recognized, with concerns ranging from the need to fund the program to maintain the level of production and reliability, to concerns about the increased funding levels and their effect on rates. Given that we have an aging hydro generation system with substantial maintenance requirements (as well as other expenses like those associated with security), the final funding levels are the minimum forecasts to continue to operate and maintain the system reliably through the next rate period.

Most of the incremental O&M costs for the FY 2007-2009 period are cost-of-living related expenses. Employee benefits, costs for materials and supplies required for maintaining the facilities, and service contracts for guard services, the fish trap and transport program, grounds maintenance, etc. are all tied to the cost-of-living indexes. The remaining O&M cost increases are associated with new requirements. Most of these new requirements like increased plant security, implementation of systems for management of maintenance activities, and environmental compliance activities are mandatory directives for the Corps and Bureau as determined by the Department of Defense and Department of Interior. The rest of the new requirements are NERC/WECC compliance and standardization of maintenance practices, which will improve the performance of the O&M program as well as ensure that system reliability requirements are maintained.

The other major factor contributing to the need for increased resource requirements in the O&M program is that the hydro system is old and has significant expenses associated with required extraordinary maintenance (particularly at Corps facilities). Most of the forced outages on the system currently are extraordinary maintenance type outages and directly affect our ability to generate. Lack of investment in the past has created a growing list of extraordinary maintenance items (estimated at $18 million plus per year through 2011) that have to be addressed in order to continue to generate revenue reliably and operate the system safely.

The incremental costs described above, when added to the significant costs required for extraordinary maintenance combine to determine a program funding need of about $250 million per year for the 2007-2009 period. This funding need for the O&M program is actually about $9 million per year more than the cost forecast of $240 million per year requested by the Corps and Reclamation and contained in this final report. The Corps and Bureau recognize the cost pressures the customers are under and will manage the hydro program to the lowest possible costs. They are committed to managing to the final PFR forecast even though O&M funding requirements are actually about $9 million per year higher than those forecasts. The agencies will accomplish this undistributed cost reduction by keeping current staffing levels generally flat through the FY 2007-2009 rate period and by seeking efficiencies through O&M program initiatives. It was noted in the PFR process that generating unit forced outages have trended up recently due to the increasing age of the system, emphasizing the need to address the increasing extraordinary maintenance requirements, as well as to continue to make capital investments in the system. Considering this, there is still some risk associated with the final PFR forecast level, particularly with respect to funding for extraordinary maintenance, but the agencies will do their utmost to minimize this risk through effective management of the hydro program.

As mentioned above, forecast levels may be updated to reflect the results of the study to review WECC/NERC requirements, and after completion of the initiative to discuss O&M practices and benchmark Corps and Bureau facilities against other Northwest regional utilities with hydro resources prior to the final power rate proposal in 2006.

COLUMBIA GENERATING STATION PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Columbia Generation Station	$215 M/yr	See debt mgt.
FY 2007-2009 PFR Base Forecast	$284 M/yr	See debt mgt.
O&M	*$201 M/yr*	
Fuel, Capital, Decommissioning Fund Contributions & NEIL	*$83 M/yr*	
FY 2007-2009 Proposed PFR Forecast	$262 M/yr	See debt mgt.
O&M	*$179 M/yr*	
Fuel, Capital, Decommissioning Fund Contributions & NEIL	*$83 M/yr*	
FY 2007-2009 Final PFR Forecast	**$263 M/yr**	See debt mgt.
O&M	*$179 M/yr*	
Fuel, Capital, Decommissioning Fund Contributions & NEIL	*$84 M/yr*	

MAY 2 DRAFT REPORT:
The Columbia Generating Station (CGS) nuclear plant provides around 9 percent of BPA's power resources. CGS is facing many issues that will affect its costs such as mandated security levels, rapidly increasing fuel prices, aging and obsolete equipment, on site spent fuel storage, and rising employee benefit costs. Energy Northwest (EN) has recently tried to address these concerns through an industry benchmarking effort to help identify areas where efficiencies can be gained without compromising the safety and reliability of the plant. The initial results show that CGS has opportunities for substantial savings through staffing reductions and a more rigorous analysis of the need for proposed projects. These estimated savings are included in the March 2005 Draft Long-Range Plan but have not been finalized or reviewed by the EN Executive Board. Several of the areas of recommended reductions in the PFR are included in the draft Long Range Plan. The final EN Long-Range Plan Revision 1 is expected to be issued in June for Executive Board review. However, BPA must provide a CGS forecast for the initial power rate proposal as part of the PFR process before the Long Range Plan is reviewed and issued. Pending a timely review from the EN Executive Board, this forecast will be updated in the final power rate proposal.

Since the base forecasts were put together for the PFR process, there has been an increase in the market price of uranium mainly driven by a supply constraint. The PFR base forecast did not take into account these higher prices; if it had, the forecast would have increased by an average of around $5 million per year over the FY 2007-2009 period. BPA and EN have agreed, and EN has issued bonds backed by BPA to finance fuel acquisition in Fiscal Years 2005, 2006 and 2007. Please see the debt management section of this letter.

	FY 2007	FY 2008	FY 2009
PFR Base	**$317 M**	**$248 M**	**$286 M**
PFR Base w/high market price uranium	$319 M	$255M	$293 M

The above table reflects the PFR Base changed only to reflect the current uranium market prices in line 2. No other changes were made.

MAY 2 DRAFT REPORT CONTINUED:

Possible Decreases Identified

1. **Proposal: Include the forecast reductions proposed in the CGS long range plan** – In response to rising costs over the past years and concerns from BPA and customers, EN has recently undergone a cost competitiveness initiative as a result of benchmarking its costs of operating the facility to other like nuclear plants. Through this process, the opportunity for significant cost savings was identified that EN is now pursuing for adoption in the FY 2007-2009 time frame. While the Long-Range Plan that includes the cost competitive initiative reductions has not been finalized by EN and reviewed by its Executive Board, BPA proposes to include these O&M savings in the initial power rate proposal at an average of $22 million per year, subject to revision in the final power rate proposal based on Board action. PFR participants supported this proposal. **Draft Conclusion: Reduce CGS O&M costs by an average of $22 million per year per draft Energy Northwest plan.**

2. **Proposal: Eliminate the license extension spending for CGS in FY 2007-2009 –** The license for CGS expires in December 2023 and EN is proposing to spend approximately $8.5 million over the FY 2007-2009 period to pursue the license extension option. This process will take about 4 years and cost approximately $14 million in total. EN will capitalize the cost of license extension over the life of the CGS. Consistent with Proposal 3 below, BPA and EN expect that EN will issue bonds backed by BPA for future EN capital expenditures. BPA and EN will jointly consider and evaluate the feasibility and value of matching bond maturity dates for new capital investments with the expected lives of those investments. Please see the debt management section. The majority of this cost is embedded in the FY 2007-2009 base PFR forecast. EN had originally started work on this project in the current rate period but chose to defer this work at least two years as a result of the cost competitive initiative. There was much discussion around this topic at the PFR workshops. Feedback so far from customers was supportive of leaving this amount in the FY 2007-2009 forecast. PFR participants also urged a public process on the ultimate decision to extend the life of the project. **Draft Conclusion: Do not eliminate CGS license extension spending.**

3. **Proposal: Forecast Energy Northwest borrowing to pay for capital items in the FY 2007-2009 period** – See Debt Management section.

4. **Proposal: Forecast Energy Northwest borrowing to pay for fuel in the FY 2007-2009 period** –See Debt Management section

The PFR Base forecast for CGS assumed that all costs in the forecast were expense funded (no debt financing). Several suggestions were made in the PFR that EN should continue to debt finance capital investments as has been the most recent practice. The resulting reduction in FY 2007-2009 expenses would be offset in part by increased debt service. EN and BPA are continuing to review capital expenditures to identify items that are candidates for debt financing. This is addressed in the debt management section. Any decisions made in the debt management area about debt financing EN investments will have an impact on the forecast for EN O&M. The O&M forecast will be updated in the rate case to reflect the impacts of any decisions related to debt management.

MAY 2 DRAFT REPORT CONTINUED:

Forecast Comparison
PFR Base and PFR Base Adjusted for Debt Financing of Capital
BPA Fiscal Years
Dollars in Millions

PFR BASE	FY 2007	FY 2008	FY 2009
O&M	209	183	210
Fuel	62	44	51
Capital	38	13	16
Decommissioning Fund Contributions & NEIL	8	8	8
Total	**317**	**248**	**285**
PFR Base Adjusted for Debt Financing	**FY 2007**	**FY 2008**	**FY 2009**
O&M	209	183	210
Fuel	62	44	51
Capital	0	0	2
Approximate Capital Financing Costs	3	5	8
Decommissioning Fund Contributions & NEIL	8	8	8
Total	**282**	**240**	**279**

The table above assumes that 100 percent of capital investments will be debt financed. The capital financing costs are the estimated debt service costs. It is possible that results could change when considered in the context of BPA's total debt portfolio.

Forecast Using the Energy Northwest Draft Long Range Plan
Assumes Debt Financing of Capital
BPA Fiscal Years
Dollars in Millions

	FY 2007	FY 2008	FY 2009
PFR Base	**317**	**248**	**286**
O&M Reduction	**(23)**	**(19)**	**(24)**
Reduction in O&M due to Debt Financing Capital	**(38)**	**(13)**	**(16)**
Increase due to Market Prices of Fuel	**5**	**8**	**8**
Increase in Decommissioning Trust Fund Contributions	**1**	**1**	**2**
Latest Revised Estimated Total O&M Forecast	**262**	**225**	**256**

The table above assumes that 100 percent of capital investments will be debt financed and does not include debt service on funds borrowed for capital spending.

MAY 2 DRAFT REPORT CONTINUED:
In summary, BPA proposes adopting the draft version of the Long-Range Plan forecast and further proposes to assume debt financing for CGS capital items, though this latter decision is one made within the rate case, not the PFR. Debt financing is also subject to EN Board action.

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Reduce CGS O&M costs per Draft Long-Range Plan	($22 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Capture fuel-savings through the uranium tails project.
- Let's decide in the future about keeping the plant in BPA's portfolio. Discuss with customers before extending EN debt beyond 2018.
- Assume more output from CGS.
- Close CGS, it is BPA's most expensive resource.
- Continue to pursue CGS license renewal.
- Include forecast reductions proposed in Long-Range Plan; debt finance qualifying capital projects; lower expense associated with nuclear fuel.
- CGS O&M and FTE and cost of production are out of line; increase is unwarranted and should be reduced substantially.

Final Report Decisions

Overall, the general comments received on the O&M portion of the CGS forecast favored the actions EN is taking to reduce FTE and overall costs. BPA is committed to working with EN to obtain the cost savings identified in the PFR process. The Final PFR forecast includes the $22 million average per year reduction in CGS O&M and increases associated with Decommissioning Trust Fund contributions. Estimated net reductions due to debt financing components of the EN forecast are reflected in the debt management section of this report. The forecast for fuel reflects an assumption that EN and BPA will be able to fully offset the steep increases in the market price of nuclear fuel through creative fuel sourcing strategies, including some financing of fuel purchases as recommended by PFR participants. The forecast for CGS O&M that will be used in BPA's final power rate studies will be contingent on the latest estimate available from EN. It will also be affected by anything that is done in the debt management area related to nuclear fuel acquisition and capital projects.

BPA has kept the funding for pursuing the license extension in its forecast but would also like to keep the option open to explore the possibility of extending CGS debt to 2024. BPA will not include this suggestion in the initial power rate proposal, but could potentially include it in final rate studies. BPA and EN will jointly consider and evaluate the feasibility and value of extending the final maturity of some existing CGS debt beyond 2018. If a change is warranted, before including such an assumption in the final proposal, BPA will review this alternative with its customers and others.

FISH & WILDLIFE PROGRAM

	Average Expense	Average Capital
FY 2002-2006 Direct Program (Integrated Program)	$139 M/yr	$20 M/yr
FY 2007-2009 PFR Base Forecast	$139 M/yr	$36 M/yr
FY 2007-2009 Proposed PFR Forecast	$143 M/yr	$36 M/yr
FY 2007-2009 Final PFR Forecast	**$143 M/yr**	**$36 M/yr**

MAY 2 DRAFT REPORT:

BPA is committed to fulfilling its fish and wildlife (F&W) obligations through managing to clearly defined performance objectives and implementing the most cost effective strategies for meeting these objectives. Fish and wildlife mitigation efforts affecting BPA power rates consist of several different components: (1) hydro operations effects (not a distinct expense line item), (2) the O&M of the Lower Snake River Compensation Plan hatchery system, (3) fish and wildlife mitigation projects funded under the Integrated Program (also known as the Direct Program or Council Program) in partnership with the Council, (4) the power share of the O&M of the Corps' fish passage facilities, its hatcheries and its juvenile salmon transportation program, (5) the power share of the O&M for the Bureau's Leavenworth fish hatchery complex, and (6) the debt service (depreciation, amortization, and net interest) associated with capital investments in fish passage facilities at the Corps of Engineers dams, and in hatcheries and land acquisitions under the Integrated Program. Additionally, 50 percent of the Council's internal operating costs are also categorized as an additional fish cost line item on BPA's Power Business Line Income Statement.

Up to this point in the PFR process, BPA has used current rate period funding levels for the capital and expense portions of the Direct or Integrated Program as placeholders. Other components reflect draft funding levels gleaned from informal discussions with the Corps, Bureau, and the U.S. Fish and Wildlife Service. With this letter, BPA will propose new draft fish and wildlife program spending levels for the FY 2007-2009 rate period. This draft proposal reflects BPA's current thinking, as informed by six fish and wildlife focused PFR workshops; numerous meetings with the Council, constituents, states, Tribes, and customers; and extensive study of the factors that may tend to push costs both higher and lower in coming years.

Possible Decreases Identified

1. **Proposal: Assume proposed installation and test mode of additional Updated Proposed Action (UPA) Surface Passage Improvements and Implement Snake River Fall Chinook Transport vs. In-River Migration Study –** One of the assumptions to be made in the FY 2007-2009 time frame is the timing and installation of additional surface passage improvements, including removable spillway weirs (RSWs), on three of the hydro projects. The PFR base case assumed installation of weirs and operation of these facilities during the FY 2007-2009 rate period at Lower Granite and Ice Harbor but assumed no surface passage improvements at The Dalles, McNary, Little Goose or Lower Monumental. PFR participants supported updating cost estimates to reflect assumptions regarding the planned installation schedule for additional improvements at these three projects. Some participants believed that this would allow spill reductions with the FY 2007-2009 rate period. BPA agrees that it is appropriate to assume installation and test mode of the UPA Surface Passage Improvements at The Dalles, McNary, and Lower Monumental. The construction costs for these facilities are funded via the Corps of Engineers' Columbia River Fish Mitigation (CRFM) project annual Congressional appropriation, with debt service not beginning until after the facilities are declared fully in-service (i.e., no longer in test mode).

   The other fish and wildlife proposal impacting hydro operations is the implementation of the Snake River fall Chinook Transport vs. In-River Migration Study. In the UPA/2004 Biological Opinion (BiOp) there is a commitment to study the relative survival of fall Chinook that migrate in river vs. via barge

MAY 2 DRAFT REPORT CONTINUED:

transportation. As part of this study, water that is normally used to generate electricity at the collector projects would be spilled instead, reducing generation. This assumption is not in the base PFR forecast and would tend to put upward pressure on rates. BPA heard many arguments for and against this evaluation. One concern was the timing of these studies and the installation of the RSWs listed above and its impact on the validity of the data collected. It was suggested that BPA postpone this test until after the RSWs are installed so studies can be conducted using the same operations from year to year. Others argue not to include it in the initial power rate proposal because it is costly. On the other hand, it was noted that these tests are part of the UPA/2004 BiOp and doing anything other that what is in the UPA/BiOp could endanger the BiOp. BPA intends to honor its commitment in the BiOp and plans to begin implementation of the test during the FY 2007-2009 time frame. Though the spill costs of this test were not included in the PFR base, neither were the spill reductions potentially resulting from the above-described installations of some surface passage improvements. The best current estimate is these spill cost increases and reductions will roughly cancel each other out. **Draft Conclusion: No net savings in spill costs.**

2. **Proposal: Fund the expected baseline O&M costs for the Lower Snake River Compensation Plan (LSRCP) hatcheries, plus some additional funding for high priority non-routine maintenance** – This program includes spending levels for 11 hatcheries, 10 satellite facilities, and monitoring and evaluation of fish health and hatchery program effectiveness in the Lower Snake River. BPA directly funds the expense portion of O&M only under a Direct Funding agreement that began in 2001. The base spending level in the PFR assumes funding for baseline O&M expenses as well as some non-routine maintenance; e.g., replacement pumps, motors, raceway and water line repairs. As with many of the items, there was much variation in suggestions regarding funding levels for these facilities. Some customers suggested BPA fund only the baseline level of O&M only with funding for additional needs made available only when BPA had positive net revenues. It was also argued that BPA not fund any capital items associated with these hatcheries. BPA proposes to fund LSRCP O&M costs at a level slightly lower than the initial proposed level, allowing some funding for the highest priority non-routine maintenance expense items but also taking into account the fact that historical actual O&M costs have come in under start-of-year budgets in recent years. BPA will negotiate a new direct funding agreement for the LSRCP with the U.S. Fish and Wildlife Service for FY 2007–2011 consistent with this principle. **Draft Conclusion: Reduce (LSRCP) O&M costs by $300,000 per year.**

3. **Proposal: Change Columbia River Fish Mitigation (CRFM) plant-in-service dates** – See Debt Management section.

Possible Increases Identified

1. **Proposal: Increase Integrated Program Funding Level** – The funding level for the Integrated (or Direct) Program covers numerous projects intended to meet BPA's mitigation objectives under the Northwest Power Act, as well as BPA's Endangered Species Act offsite F&W requirements under biological opinions from the U.S. Fish and Wildlife Service and NOAA Fisheries. Through the PFR process BPA has engaged interested parties in four different funding alternatives for this program. These alternatives ranged from $126 million per year to $174 million per year. Current rate period expense funding for this Program is $139 million per year, and the non-discretionary FY 2001-2004 funding level was determined to be approximately $125 million per year. As with many of the other fish related costs, the feedback was wide and varied. Some customer groups supported the lowest cost alternative, resulting in a $13 million per year reduction in spending from the current levels. Other customers proposed the low scenario but with the provision that in good water years, additional funding should be available up to an agreed upon percentage for previously-approved but unfunded projects, with provision to "bank" the money for future years if all approved projects were already funded. Other commenters suggested that funding levels remain at current levels for the next rate period, allowing time for more clearly formulated "rolling-up" and prioritization of subbasin plan driven fish and wildlife restoration efforts. The Columbia Basin Fish and Wildlife Authority (CBFWA) and others opined that even under the highest funding level, BPA would be under-funding its mitigation obligations associated with recently completed subbasin plans. CBFWA's preferred alternative advocated Integrated Program spending levels rising to $460 million annually. In the PFR, BPA proposed, and many commenters supported, that project funding be allocated such that 70 percent would go to on-the-ground projects (primarily hatcheries and habitat enhancement projects), 25 percent to research, monitoring

MAY 2 DRAFT REPORT CONTINUED:

and evaluation (RM&E), and 5 percent for coordination/information management and administration. The purpose of this allocation is to steer additional funding to on-the-ground projects, such as those recommended in the recently completed subbasin plans, without necessarily increasing overall funding levels. An analysis of FY 2001-2004 program funding indicated that only about 60 percent of total funding went to on-the-ground work and nearly one-third of total funding went to RM&E. One commenter suggested modifying the 70/25/5 allocation guidelines, to move even more funding ($10 million) from RM&E, and to also reduce BPA's fish and wildlife overhead costs by $2 million (approximately 20 percent) and move these dollars to provide for even greater on-the-ground funding levels without increasing overall funding of this program.

In numerous discussions with Council members, Council staff, and CBFWA members, drivers influencing future work efforts in the Integrated Program project categories of hatcheries, habitat work, RM&E and coordination were discussed. Among the drivers for increased funding are habitat restoration activities prioritized in subbasin plans and the 2004 FCRPS UPA/BiOp habitat enhancement work in the Columbia Basin tributaries. Additional drivers identified include inflation costs driven by salaries, health insurance costs and rising energy costs. However, the program's expense budget increased from $100 million per year in the FY 1997-2001 period to $139 million per year in the current period. While much of this additional funding was intended to cover increased ESA requirements, it also provided a very significant allowance for inflation. The allocation guidelines that were extensively discussed in the PFR process would provide for substantial increases in available funding for habitat enhancement work under the auspices of the subbasin plans and the new BiOp by shifting some funding away from RM&E and coordination contracts. However, some commenters pointed out that there are substantial pressures from both NOAA Fisheries and the Council's independent science groups (ISRP and ISAB) for elaborate monitoring and evaluation efforts, making such funding shifts to on-the-ground work challenging to accomplish. Additionally, it was suggested that given the hurdles associated with reinventing the RM&E program, funding decisions on habitat restoration projects should precede RM&E project selection, so as to not create a situation where RM&E funding pressures adversely affect available funding for habitat work. Additionally, under the Northwest Power Act, BPA has funded a substantial wildlife mitigation effort to replace habitat lost by inundation effects resulting from reservoir construction and operation. In recent years, some of this mitigation has been funded using capital borrowing under BPA's borrowing authority consistent with BPA's capitalization policy. Several Integrated Program partners have expressed strong concerns about the difficult thresholds required by BPA for using capital funding to meet wildlife mitigation objectives and are frustrated with the slow pace towards meeting such objectives. Some have suggested that Integrated Program funding levels be increased so as to use additional expense funding for increasing the pace of wildlife mitigation. Others suggested that the region be more aggressive in the pace of wildlife mitigation efforts, but with active use of BPA's F&W capitalization policy as opposed to using the expense budget. To more fully utilize BPA's F&W capital budget over this next rate period, new focus and energy will be needed to identify and plan projects that qualify for capital assignment under BPA's capitalization policy.

Draft Conclusion: After weighing all these arguments drivers, and extensive comments in the PFR process, BPA proposes to fund the integrated program at the $143 million per year expense level and to shift roughly $15 million of FY 2001-2004 average current funding away from RM&E and RM&E-related support activities to fund additional habitat enhancement efforts, and maintain hatchery programs - The result of this funding shift would be that overall funding for on-the-ground work (primarily habitat improvement and hatchery O&M) would be about $15 million greater than FY 2001-2004 levels, providing for both a substantial funding increase for subbasin plan- and UPA-driven habitat enhancement work, and also an allowance for inflation in the O&M for hatcheries funding under the program.

The completion of 58 subbasin plans offers the region the opportunity to refocus program implementation to target specific, high priority biological objectives that may appropriately be addressed as mitigation for the FCRPS. Additionally, the recently completed Updated Proposed Action and NOAA Fisheries BiOp call for habitat improvement efforts as strategies for avoiding jeopardy to ESA-listed salmon and steelhead. The development of BPA's PISCES computer program, enabling projects to be managed and tracked from

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solicitation to completion, will offer the ability for projects to be managed for specific work elements, accruals to be tracked as they are invoiced, and for the region to monitor progress towards more clearly defined performance objectives. All of these factors offer the region the opportunity to use the coming rate period as one of transition to a more performance based approach. To bring about this repositioning of BPA's implementation of the program, additional work needs to be done in the following areas:

- Subbasin plans need to be "rolled up" to provincial objectives (e.g., population goals, by province, for Chinook salmon) in a manner relevant to FCRPS responsibilities.
- Recommendations to BPA for program funding need to be prioritized to show where and when different species or geographically which habitat should be the focus for the next several years.
- Performance standards also need to be developed for use in the solicitation process (e.g., physical standards (streamflow levels, river miles of blocked habitat reopened, etc) and biological standards (population levels).
- Accounting for mitigation completed to date with ratepayer funding.
- Reallocating program funding to have 70 percent of funding serve projects that directly benefit F&W.
- Accounting for the effects of ocean conditions on anadromous fish.
- Assessing the role in the program for the causal factors for population decline that go beyond factors associated with the FCRPS or the hydro system.
- Creating new partnerships and cost-sharing protocols for application to mitigation objectives and strategies, especially where there are shared responsibilities.
- Completion of recovery plans and assessment of BPA's responsibilities under them.
- Adhering more closely to the program's 70/15/15 funding allocation guideline for anadromous fish, resident fish, and wildlife, respectively. This allocation would include and be consistent with the principles contained in the UCUT proposal that was submitted in the fish and wildlife PFR meetings.

Many of these issues will be addressed in the next 2 years, through, most likely a project selection process or a Council Program Amendment process. These efforts will not be finished in time for selecting proposed program spending levels for the PFR or the rate case initial proposal. In addition, a regionally accepted methodology for looking at the current Integrated Program project portfolio and determining which discretionary projects should continue in FY 2007, which projects should no longer be funded, and which new projects should begin being funded, is still at the initial levels of a work-in-progress. After tasks mentioned above are complete, the transition will be able to move to its final stages where the current project portfolio can be more rigorously assessed for how well it meets biological and physical performance objectives in the most cost effective manner.

After much debate over funding levels for F&W, BPA proposes the following changes to the forecasted amounts in the PFR.

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Increase Integrated Program Spending Level	$4 M/year
Reduce US Fish & Wildlife Service Spending Level	($0.3 M/year)

Summary of Comments Received on Proposed PFR Forecast

BPA Division of Fish and Wildlife conducted public review meetings regionally throughout the Power Function Review. The comment review period provided the Council, customers, states, tribes and other interested parties the opportunity to give feedback on F&W program funding levels for the 2007–2009 rate period.

- Reign in Fish & Wildlife (F&W) spending. The costs are being pushed to unacceptable levels.
- Support adequate funding for F&W in the next BPA rate case. Current funding is inadequate.
- Funding must complement the tribes' F&W management and support projects consistent with treaty, trust, and other obligations; support the budget developed by F&W managers to implement subbasin plans and other tribal proposals.
- Entering into long-term funding agreement on F&W will not allow BPA the flexibility it needs to prioritize expenditures.
- Coordinate Corps research program with what is happening in the Integrated F&W Program.
- $356.9 million understates financial and environmental costs of fish operations.
- Power is available to replace the generation at the Lower Snake River dams.
- The CBFWA recommendation to ramp up funding for F&W to $240 million is essential; a number of events could significantly increase F&W expense; the ESA may require more funds for monitoring.
- The F&W program has reached an unacceptably high level of cost. There is need for greater accountability and efficiency in operating the F&W program; need scientific review of CRFM project; greater coordination needed for RM&E; need a fresh look at capitalization, depreciation, and amortization of F&W investments.
- Reconsider the need for the Snake River fall Chinook transport study.
- Try a year without spill and see what happens; we are spending $110 million a year on spill.
- Customers would be better off moving the RSWs along; take the $23 million in funding out for the fall Chinook transport study. Look at the medium range ($144 million) for Integrated Program funding, take another $10 million out of RME, $2 million from BPA overhead and direct another $12 million to on-the-ground projects. Customers need better information about when the decisions will be made in other F&W processes so our participation counts.
- BPA should take a leadership role to stop the predation and harvest.
- We need better studies about what we are getting with F&W expenses of this magnitude.
- Wait to implement the transportation study until RSWs are installed. Study should not span period with and without the RSWs, which could cloud results.
- BPA spent $15 million on subbasin plans, and now it is a struggle to implement them. F&W managers have not been able to fully implement their programs.
- Adequately fund F&W responsibilities under ESA and Northwest Power Act.
- Many F&W related points, including: further increases to F&W funding are unjustified at this time; measure of success should be biological effectiveness; support proposal to reprioritize toward on-the-ground projects; fund only activities that relate directly to BPA's mitigation obligations.
- BPA budget assumptions place implementation of subbasin plans and wildlife component of F&W program at serious risk. Final proposal should maintain flexibility to fund with capital wildlife acquisitions that cost less than $1 million. Assumed reduction in RME costs is too aggressive, and inflation factor is inequitably low.
- Increase in Integrated Program budget is necessary to meeting obligations under the Northwest Power Act and ESA. Willingness to shift away from RME is speculative; budget sufficiently to fund the UCUT proposal for the Upper Columbia Eco-region; create a firewall around the resident F&W allocations; conditional approval of 70/25/5 split; fund BPA F&W overhead from other sources and not Integrated Program budget.

- Customers now have rigorous justification for F&W expenditures and if they refuse to support the necessary funding, other authorities will likely intervene forcefully.
- Support shift of funding in Integrated Program to 70/25/5 allocation; agree with need for greater RME coordination; it is inappropriate for BPA customers to mitigate for all problems identified in the subbasin plans and we object to paying for mitigation not directly related to federal hydro impacts. Further increases in F&W funding are unjustified at this time.
- Accelerate installation of surface bypass systems; modify Snake River fall Chinook transportation study; fund baseline O&M and provide greater clarity on role of hatcheries in meeting mitigation obligation; no increase in Integrated Program budget without biological goals and objectives and priorities to meet BPA mitigation obligation; more must be done to reduce F&W mitigation costs.
- Assume in-river transportation study will be moved out of the next rate period; include revenue from additional generation resulting from RSWs; could support $143 million level for Integrated Program if it includes obligations for subbasin plans, thorough bottoms-up examination of program, no special rate adjustment for unanticipated costs; amortize long-lived assets over their useful lives.
- May be time to survey BPA's electric consumers as to whether they would accept a .02 cent per kWh increase to forego the benefits and costs of Lower Snake River dams.

Final Report Decisions

Comments received on the F&W Integrated Program varied widely among participants. As stated in the draft report, BPA remains committed to an ongoing, progressive implementation of an integrated and collaborative plan for F&W mitigation and recovery. To be truly results-driven, our investments throughout the basin – aimed at the needs of both listed and non-listed species – must be linked to clearly defined biological objectives, must be as cost-efficient as possible, and must be linked to mitigating for the impacts of construction and operation of the federal hydropower system, and consistent with the *Columbia Basin Fish and Wildlife Program* vision of protecting and mitigating the natural ecological functions, habitats, and biological diversity of the Columbia River Basin. In recent years, BPA has made considerable strides to improve contracting, financial management, progress reporting, and program evaluation. Our renewed emphasis on performance provides a solid foundation for managing the Direct Program into the future.

As we begin planning for review and implementation of projects in FY 2007-2009, the funding allocations of 70 percent for on the ground projects, 25 percent for RM&E and 5 percent for coordination proposed by BPA in the PFR will be closely followed. During this new and challenging transition period, in coordination with the Council, regional F&W managers, tribes and others, we intend to move to a more performance and results-based approach for project solicitation and program management. It will emphasize sound science, greater cost-sharing and partnership agreements to address offsite mitigation of impacts caused by sources other than the FCRPS. In addition, we will emphasize this performance-based approach in BPA's program management priorities, policy goals, and implementation funding decisions through this reprogramming of current spending and in the prioritizing of new investments where needed. The result will be a more efficient project review and implementation process that facilitates the results-based work of the program and maximizes the effective application of fiscal and human resources.

1. **Regional Agreement Among States, Tribes, and Federal Agencies on Hydro System Management -** NOAA Fisheries, BPA, Bureau, and the Corps have been working collaboratively with the governors of Oregon, Washington, Idaho, and Montana for several months to address both short-term and long-term FCRPS management and operation solutions. We recognize that this work has been difficult – we have not yet reached agreement on these critical issues – and that the challenges are great. But we all share a tremendous responsibility and commitment to continuing our dialogue to develop a salmon recovery approach that meets mutually agreed upon biological objectives, that delivers clear results, and is regionally sustainable for the future. While it is unclear at this time whether the agreement, if reached and finalized, would change costs, we expect it could change how funding is used for recovery measures and also help make system operations and costs more predictable. However, we are not changing the forecast for the final report, and this issue will be updated as conditions warrant.

2. **Mitigating Additional Costs of Increased Summer Spill Requirements -** In *National Wildlife Federation v. National Marine Fisheries Service* the court on June 10, 2005, entered an order requiring spill in addition to what the FCRPS Action Agencies had already planned under the UPA. The costs of these additional spill operations to BPA ratepayers in 2005 are estimated to be $67 million. The amount will vary with actual energy market prices and stream flow conditions. BPA has not decided how to manage these costs if they are carried into FY 2007-2009. Due to the relationship between the financial effects of hydro system operations requirements for fish and the direct program, reductions in program cost levels may be necessary if generation and revenue effects are expected to be significant and persistent throughout the FY 2006-2009 period.

3. **Integrated Program Funding Level –** Through the PFR process and comment period, BPA has engaged interested parties in considering driving forces that might increase or decrease the program spending levels. We evaluated many drivers and their accompanying rationales, and generally reflected them in four different funding alternatives for the program. These alternatives for the expense portion of the program ranged from $126 million per year to $174 million per year. Current rate period expense funding for this program is $139 million per year. As with other areas of program investment, the feedback regarding the scope of direct expenditures was lively and diverse. Some customer groups supported the lowest-cost alternative, resulting in a $13 million per year reduction in spending from the current levels. Other customers proposed the low scenario but with the provision that in good water years, additional funding should be available up to an agreed upon percentage for previously-approved but unfunded projects, with provision to "bank" the money for future years if all approved projects were already funded. Other commenters suggested that funding levels remain at current levels for the next rate period, allowing time for more clearly formulated "rolling-up" and prioritization of subbasin plan driven F&W restoration efforts. The Yakama Nation and the CRITFC and others opined that even under the highest funding level, BPA would be under-funding its mitigation obligations associated with recently completed subbasin plans. These Tribes advocated Program spending levels of $310 million annually.

In the PFR, BPA proposed, and many commenters supported, that project funding be allocated such that 70 percent would go to on-the-ground projects (primarily hatcheries and habitat enhancement projects), 25 percent to research, monitoring and evaluation (RM&E), and 5 percent for coordination, information management, and administration. The purpose of this allocation is to steer additional funding to on-the-ground projects, such as those recommended in the recently completed subbasin plans, without necessarily increasing overall Integrated Program funding levels. An analysis of FY 2001-2004 Program funding indicated that less than 60 percent of total funding went to on-the-ground work and nearly one-third of total funding went to RM&E. One commenter suggested modifying the 70/25/5 allocation guidelines, to move even more funding ($10 million) from RM&E, and to also reduce BPA's fish and wildlife overhead costs by $2 million (approximately 20 percent) and move these dollars to provide for even greater on-the-ground funding levels without increasing overall funding of this program.

In numerous discussions with Council members, Council staff, and CBFWA members, drivers influencing future work efforts in the Integrated Program project categories of hatcheries, habitat work, RM&E and coordination were discussed. Among the suggested drivers for increased funding are habitat restoration activities prioritized in subbasin plans and the 2004 FCRPS UPA/BiOp habitat enhancement work in the Columbia Basin tributaries. The new subbasin plan priorities, however, created greater clarity for priorities, not new FCRPS obligations. Additional drivers identified include inflation costs driven by salaries, health insurance costs and rising energy costs. However, the program's expense budget increased from $100 million per year in the FY 1997-2001 period to $139 million per year in the current period. While much of this additional funding was intended to cover increased ESA requirements, it also provided a very significant allowance for inflation. The allocation guidelines that were extensively discussed in the PFR process would provide for substantial increases in available funding for habitat improvement work under the auspices of the subbasin plans and the new BiOp by shifting some funding away from RM&E and coordination contracts. However, some commenters pointed out that there are substantial pressures from both NOAA Fisheries and the Council's independent science groups (ISRP and ISAB) for elaborate monitoring and evaluation efforts, making such funding shifts to on-the-ground work challenging to accomplish. Additionally, it was suggested that given the hurdles associated with reinventing the RM&E program, funding decisions on habitat projects should precede RM&E project selection, so as to not create a situation where RM&E funding pressures adversely affect available funding for habitat work. Additionally, under the Northwest Power Act, BPA has funded a substantial wildlife mitigation effort to replace habitat lost by inundation effects resulting from reservoir construction and operation. In recent years, some of this mitigation has been funded using capital borrowing under BPA's borrowing authority consistent with BPA's capitalization policy. Several commenters expressed strong concerns about the difficult thresholds required by BPA for using capital funding to meet wildlife mitigation objectives and are frustrated with the slow pace toward meeting such objectives. Some have suggested that Integrated Program funding levels be increased so as to use additional expense funding for increasing the pace of wildlife mitigation. Others suggested that the region be more aggressive in the pace of wildlife mitigation efforts, but with active use of BPA's F&W capitalization policy as opposed to using the expense budget. Taking all these comments into consideration, BPA believes that its proposed $143million Fish and Wildlife Program funding level allows for significant additional funding of high priority habitat improvement efforts reflected in the recently completed subbasin planning effort, through the proposed 70/25/5 funding allocations between on-the-ground work, RM&E and coordination, through increased application of cost sharing and partnering where there are shared mitigation obligations, and through more strategic, efficient and better coordinated RM&E. BPA also believes its wildlife mitigation is on a steady pace toward achieving mitigation obligations, with up to 34,000 acres protected in FY 2004-2005—nearly one-tenth of what the FCRPS inundated. To more fully utilize BPA's capital funding availability over this next rate period, new focus and energy will be needed to identify and plan projects that qualify for capital assignment under BPA's capitalization policy.

4. **Proposed installation and test mode of additional Updated Proposed Action (UPA) Surface Passage Improvements and Implement Snake River Fall Chinook Transport vs. In-River Migration Study –** Though the cost of increased spill for the Snake River fall Chinook transport versus in-river evaluation were not included in the PFR base, neither were the potential spill reductions that may result from installations of surface passage improvements at The Dalles, McNary, Little Goose or Lower Monumental dams. The best current estimate is these spill cost increases and reductions will roughly cancel each other out. BPA acknowledges concerns raised about the timing of the transport versus in-river evaluation relative to installation of surface passage technologies. Given recent legal rulings about the 2004 NMFS BiOp and UPA, it is unclear what degree of flexibility there is to modify the timing of the evaluation. BPA will work with other federal agencies to further examine this issue. If adjustments in the timing can be made in a manner consistent with BPA's obligations under the ESA, BPA will reflect any appropriate schedule changes in the final power rate proposal next year.

OTHER

	Average Expense	Average Capital
FY 2002-2006 Other	$83 M/yr	N/A
FY 2007-2009 PFR Base Forecast	$120 M/yr	N/A
FY 2007-2009 Proposed PFR Forecast	$105 M/yr	N/A
FY 2007-2009 Final PFR Forecast	**$105 M/yr**	**N/A**

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Throughout the PFR workshops several items where changes could occur were identified that did not fall into the major program areas examined during the PFR. Nonetheless, BPA thought it important to include these areas in the closeout report since they have an impact on rates.

1. **Proposal: Remove Spokane Settlement forecast** – Discussions have gone on for many years of providing the Spokane tribe with compensation for lost land resulting from federal dam construction, similar to the settlement BPA currently has with the Colville tribe. Congress has considered legislation creating such compensation. A placeholder for such compensation payments was included in the PFR Base. However, it is not appropriate to plan on such payments unless and until Congress has authorized them. **Draft Conclusion: Remove the forecast of Spokane Settlement costs in the rate case initial proposal FY 2007-2009 spending levels and revise it in the final proposal if it passes.**

2. **DSI Benefits Forecast** – During the time the PFR base forecast was assembled, there was an outstanding issue of what type of benefits the DSI's would receive in the FY 2007-2009 time frame and the cost associated with them. The PFR base adopted the then proposed DSI Record of Decision (ROD) amount of $40 million per year in benefits and assumed it would be delivered in money rather than power as a placeholder. Understanding this issue is one that will be resolved in the Short-Term Regional Dialogue and rate case arena, the forecast in the PFR will be updated in the rate case to reflect the decisions from the Regional Dialogue conclusions. **Draft Conclusion: This item will be updated in the rate case to reflect the outcomes from the Supplemental Regional Dialogue ROD on DSI Service.**

3. **Reduction in Environmental Benefits Forecast –** When the PFR base forecast was put together there was a forecast of around $7 million per year for mitigation of the proposed spill reduction in FY 2004 that was accidentally carried forward from that timeframe. This should not have been included and BPA has since made this correction and has included it in the forecast accompanying this letter in the "other" category. **Draft Conclusion: Update Environmental Benefits forecast in closeout report.**

4. **Proposal: Adopt Conditional Budgeting** – An idea brought up at the PFR workshops was to link BPA spending levels to its financial performance every year. When BPA faced a year where financial results fell below assumptions in the rate case then spending levels would be reduced to help offset some of the losses. On the other hand, when BPA had a good financial year the spending levels could be increased to make up some of the projects that were put off in the low water years. This would reduce the need for risk mitigation costs in the rate case and that BPA spending would bear some of the burden in poor financial years. BPA's employee award program, for example, already has this variability built into it. Given the magnitude of the risk management challenge in this next rate period, BPA considered this concept carefully. However, three concerns make BPA reluctant to pursue this concept at this time: First, it appears doubtful that enough of the budget can be put "on the margin" in this way to make a significant impact on risk mitigation costs, without jeopardizing essential functions. Second, constructing and implementing such a construct could add significant complexity. BPA is reluctant to add complexity unless risk management benefits are significant. Third, it is not clear how this concept could be

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implemented without making program cost levels a rate case issue – a step BPA does not wish to take. **Draft Conclusion: Do not pursue conditional budgeting.**

BPA Proposals	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Remove Spokane Settlement Amount	($6 M/year)
Update Environmental Benefits forecast	($7 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Leave IOU benefits open to discussion; perhaps include ceiling.
- Do not subsidize the aluminum companies.
- Do not lock budget decisions down now.

Final Report Decisions

Cost control is an important aspect to BPA no matter how big or small the budget item. In the PFR process there were several categories of costs either outside the scope of the PFR (i.e., DSI benefits) or small enough not to warrant a workshop to understand the costs associated with the forecast. The categories associated in the "other" category consisted of items generally in the single-digit forecasts and many times ones where we make payments based on a calculation. A few of the items were discussed with a certain program area such as Council and U.S. Fish & Wildlife in the F&W workshops. The items in the "other" category are:

Other	FY02-06 Average	FY07-09 Average - PFR Base	FY07-09 Average - PFR Proposed	FY07-09 Average - PFR Final Decision
-US Fish & Wildlife Lower Snake Hatcheries	$ 16.6	$ 19.8	$ 19.5	$ 19.5
-Planning Council	$ 8.3	$ 9.1	$ 9.1	$ 9.1
-Colville Settlement	$ 17.9	$ 17.4	$ 17.4	$ 17.4
-Spokane Settlement	$ -	$ 6.7	$ -	$ -
-Trojan Decommissioning	$ 5.0	$ 5.6	$ 5.6	$ 5.6
-WNP 1&3 Decommissioning	$ 0.1	$ 0.1	$ 0.1	$ 0.1
-PNCA Headwater Benefit	$ 1.8	$ 1.7	$ 1.7	$ 1.7
-Hedging/Mitigation	$ 4.1	$ 0.3	$ 0.3	$ 0.3
-Other Environmental Requirements	$ 3.0	$ 7.5	$ 0.2	$ 0.2
-Civil Service Retirement System	$ 17.1	$ 11.6	$ 11.6	$ 11.6
-Other Income, Expenses, Adjustments (DSI benefits for FY07-09)	$ 9.2	$ 40.0	$ 40.0	$ 40.0
Total	**$ 83**	**$ 120**	**$ 105**	**$ 105**

The comments received on this category focused on three main themes: DSI benefits, not keeping budgets out of the rate case, and IOU benefits. While DSI benefits are a matter that will be decided in the Short-Term Regional Dialogue forum, it is important to note that a $40 million per year placeholder was used in the PFR forecast. The PFR did not assume any change to this forecast in the final report so if there is a difference in the amount decided upon in the DSI ROD it will either help or hinder the progress of the PFR total reductions identified.

While the argument to keep budgets in the rate case has been made, BPA has been taking a firm stand on this issue since the 1987 rate case. The Administrator took the position during and at the conclusion of each of the rate cases that rate hearing requirements do not comprehend all aspects of BPA's business, but only legitimate ratemaking issues; program and program level determinations are not ratemaking issues. Moving cost decisions into the rate case forum would also potentially bring those decisions into the purview of FERC review of BPA rates, thereby greatly expanding the scope of that review. It is BPA's intent to keep that position in the FY 2007-2009 rate case proceedings.

The IOU benefits are based on a calculation contained in a contract and already include a floor and ceiling. The method itself cannot be up for debate in the rate case because it is contractually defined, but there are still some aspects of uncertainty that will be open for discussion.

After consideration of the comments received in this category from PFR participants, the conclusion of the PFR is to not change the forecasts in the "Other" category from the draft report.

DEBT MANAGEMENT

	Average Expense	Average Capital
FY 2002-2006 Debt Management	$892 M/yr	N/A
FY 2007-2009 PFR Base Forecast	$1,003 M/yr	N/A
FY 2007-2009 Estimated PFR Forecast	$965 M/yr	N/A
FY 2007-2009 Final Estimated PFR Forecast	**$965 M/yr**	**N/A**

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Unlike many of the programs studied and discussed in the PFR process, the debt management area is not a program but a result of the capital investments the agency has made over time, forecasts for future capital investment, and BPA's debt management decisions. The PFR included discussion on these items because it was important for participants to understand the implications of past debt management decisions and proposed capital spending levels. But how BPA includes decisions and assumptions on debt management are rate case issues and will be discussed in that forum. With that said, the PFR process brought attention to many issues associated with program funding proposals. BPA's current thoughts are described under each topic below.

Possible Decreases/Increases Identified

1. **Proposal: Change Columbia River Fish Mitigation (CRFM) mitigation analysis plant-in-service schedule** – The Corps receives appropriated funds for the CRFM project to mitigate impacts to anadromous fish passage of construction of the Columbia/Snake River dams. Currently there is approximately $300 million of mitigation analysis being held in "construction work in progress" related to alternative analysis, prototype development and other studies done under this program. The Corps is currently evaluating to determine the appropriate schedule for putting this amount into "plant in service", at which time it will become BPA's obligation to repay the power share. The Corps has provided two different "bookend" scenarios (A&B). Many customers have expressed a preference for scenario B to avoid having additional costs hit the FY 2007-2009 rates. It is ultimately not BPA's decision when to put this amount into service. However, if the Corps has not made a decision at the time BPA prepares its initial power rate proposal, BPA will decide what assumption to include in its initial power rate proposal. This forecast may be updated to reflect the Corps decision prior to the final rate proposal. **Draft Conclusion: At this time, BPA prefers the Corps use scenario B.**

2. **Proposal: Debt finance CGS capital projects with final maturity of FY 2018** – Through 2001, EN included capital expenditures in its O&M projections and they were revenue financed through BPA rates. In the SN CRAC rate case, BPA and EN agreed that EN would issue bonds backed by BPA to finance expenditures that qualified under GAAP as capital investments for the FY 2002-2006 period. EN issued the first bonds for new capital investments in 2003. All new capital investment debt has been issued with the final maturity of 2018. As we head into the next rate period it has been suggested in the PFR that BPA and EN continue this practice of financing capital items through debt rather than revenue financing. **Draft Conclusion: Though the PFR is not the process for this decision, BPA expects to assume debt financing for CGS expenditures that qualify under EN's capitalization policy and limit the final maturity to FY 2018 in its initial power rate proposal. BPA and EN will jointly consider and evaluate the feasibility and value of matching bond maturity dates for new capital investments with the expected lives of those investments. Before including such an assumption in the final power rate proposal, BPA will review this alternative with its customers and others.**

3. **Proposal: Finance Nuclear Fuel** – The cost of fuel has always been treated as an expense through BPA rates, the EN net-billed budget, and BPA financial statements. On their financial statements, EN capitalizes fuel over the expected life. BPA assumed continued expensing of fuel in the base PFR forecast. Some

MAY 2 DRAFT REPORT CONTINUED:

PFR participants argued for debt financing fuel to help spread the costs over time. EN generally purchases roughly the same amount of fuel as is burned by CGS each year. Under these circumstances, borrowing to pay for fuel costs is somewhat similar to borrowing to pay O&M costs. However, if fuel for several years of CGS operation is purchased in one year, financing such "lumpy" fuel costs can make sense as a means of spreading the costs to the years in which the fuel is actually burned. BPA and EN have agreed and EN has issued bonds backed by BPA to finance fuel acquisition in FY 2005, 2006, and 2007. **Draft Conclusion: EN has issued bonds to pay for up to $93 million in fuel costs in FY 2005, 2006 and 2007. Initial proposal debt service forecasts will include debt service on those bonds. Remaining decisions on this topic will be made in the rate case.**

4. **Proposal: Change the amortization period for Conservation investments** – In the FY 2002-2006 rate case it was determined that conservation augmentation investments should be amortized over the term of the existing contracts, i.e., through FY 2011. The decision was made on the basis that these conservation augmentation investments had benefits that were only certain to accrue for as long as the contracts were in place. This decision has created concern among the customers because in the last few years of the contract period any new conservation investments are essentially expensed under this treatment. BPA examined the current practice against 5- and 15-year recovery periods and agrees that retaining the current policy of recovering all conservation costs by FY 2011 is too conservative. However at present there are unresolved issues about how conservation costs will be recovered in a likely tiered rate structure post-2011. Until this is resolved, a relatively short recovery period appears more prudent. In addition, preliminary repayment model analysis indicated only a small reduction in debt service resulting from the longer recovery period. **Draft Conclusion: Rather than the 10-year declining amortization period policy in place for the currently operating Conservation Augmentation program, for conservation acquisition activities planned to commence in FY 2007, BPA is leaning towards establishing a 5-year Straight Line amortization period policy.**

5. **Proposal: Utilize a revised interest rate forecast for the initial power rate proposal** – This is a standard practice in the power rate cases when circumstances warrant an updated forecast and will continue to be this rate case. The interest rate forecast used for the PFR Base is not significantly different from current forecasts. **Draft Conclusion: BPA will update the interest rate forecast in the initial power rate proposal.**

6. **Proposal: Include interest income on cash balances from the Bonneville Fund** – This is a standard practice in the power rate cases and will continue to be this rate case. The PFR is not a place where this decision is made, but because its base forecast did not include this assumption it needed to be noted. This amount will be greatly influenced by the rate structure adopted in the rate case. A rough estimate of the additional interest income is around $10 million per year. **Draft Conclusion: BPA will include interest income on cash balances in the initial power rate proposal.**

7. **Proposal: Extend some of the current CGS debt beyond FY 2018 –** The current practice is not to place any debt past FY 2018 when refinancing debt in support of the debt optimization program. This is in compliance with the EN Board policy. BPA will analyze the effects on ratepayers of implementing this suggestion and share its results with the EN Executive Board over the ensuing months. **Draft Conclusion: BPA will not include this suggestion in the initial power rate proposal, but could potentially include it in final rate studies. BPA and EN will jointly consider and evaluate the feasibility and value of extending the final maturity of some existing CGS debt beyond 2018. If a change is warranted, before including such an assumption in the final proposal, BPA will review this alternative with its customers and others.**

8. **Proposal: Lengthen the amortization period for F&W capital –** BPA's long-standing policy is to amortize BPA's F&W capital projects over a 15-year life. In comparison, any fish-related capital investments made at the dams are depreciated, with the rest of the project assets, over 75 years and repaid over 50 years. During the PFR process, several customers argued that the BPA F&W amortization criteria are too stringent and that the amortization period should be lengthened. This is a rate case issue. However, at this time BPA believes it is appropriate to continue with its existing policy, given that BPA's F&W

MAY 2 DRAFT REPORT CONTINUED:

investments are non-revenue producing assets, not attached to revenue-producing assets (as the Corps investments are), and are not owned by BPA. A change in accounting policy to allow more capital spending for assets only allowed to be capitalized under Financial Standards Board Statement #71 does not seem to be prudent, given BPA's limited borrowing authority. **Draft Conclusion: It is not appropriate to change the F&W amortization policy.**

Many of the decisions associated with the debt components of the power rates are appropriately debated in the power rate case forum. But BPA thought it important to show in the PFR the impact of past and future debt management decisions since these impact power rates. This PFR final report is not making any decisions associated with the debt management issues but instead is intended to portray BPA's current thinking on these issues heading into the FY 2007-2009 power rate case. The savings associated with individual items are current estimates of the incremental revenue requirement impacts of each action. They are indicative of what we would expect, but when several actions are taken together the results are not necessarily additive. In other words, the total savings may well differ when the items are combined in repayment studies.

BPA's Current Thinking	Proposed PFR Base FY 2007-2009 (Reductions)/Increases
Debt Finance CGS Capital	($13 M/year)
Adopt different CRFM schedule	($5 M/year)
Change Conservation Amortization Schedule to 5 years	($ 10 M/year)
Include Interest Income on cash balances from BPA fund	($ 10 M/year)

Summary of Comments Received on Proposed PFR Forecast

- Include a placeholder for debt reduction in revenue requirement.
- Resist pressures to push current expenses into future rate periods – revenue finance a portion of capital outlays.
- Re-examine capital policy regarding habitat acquisition; explore making capital more freely available.
- Work with other Federal agencies to minimize rate impacts of debt management.
- Increase amortization period of BPA-funded F&W investments.
- Amortize conservation investments over useful life of measures.
- Pursue opportunities to alter non-federal debt service associated with EN.

Final Report Decisions

As noted previously, debt management issues are not decided in the PFR. We are using PFR comments to inform our discussions of and decisions on debt management assumptions that will be incorporated into the initial power rate proposal. Those assumptions are subject to debate in the rate case process. At least two significant areas of public comment on the draft report will be explored further before final power rates are set – the possibility of a longer amortization period for conservation capital and the possibility of recovering CGS capital over the full license period of the project (i.e., through 2024). Both of these actions were advocated by PFR participants. The conservation capital amortization period will be reviewed next year, based on progress defining long-term conservation programs in the Long-Term Regional Dialogue process. BPA will further discuss the recovery period for CGS capital with the EN Board and interested customers and others. Both of these are power rate case issues and will be addressed within the rate case process. Any changes will be reflected in the final power rate proposal next year.

RISK

MAY 2 DRAFT REPORT:
The PFR looks at the costs associated with the PBL and provides an opportunity for public comment on those costs prior to them being included in the rate case. While the topic of risk mitigation is not a PFR topic it will be a major component of BPA's power rates in FY 2007-2009. Therefore, participants voiced concern that they needed to get a sense of the total picture in order to provide meaningful input into the PBL cost structure. In addition, BPA realized that risk mitigation will be a big issue in the FY 2007-2009 power rate case and wanted to begin discussions about different ways to mitigate risks. As a result, BPA included risk mitigation workshops in the PFR process with the understanding that any numbers used were preliminary and will be updated in the rate case itself. This first Risk workshop was really the beginning of FY 2007-2009 rate case workshops.

Risk mitigation will be a key topic in the next rate period because risk management is a greater challenge than in prior rate cases. Several factors are driving this amount to unprecedented levels. Gas prices have been at a historic high over the last few years. These gas prices are putting upward pressure on the electric power market prices. With the higher market prices also comes more volatility (risk) – not only does the volatility of prices for electricity increase, but the financial impact of hydro uncertainty increases, since each incremental or decremental MW of generation is worth more. This tends to increase the revenues from secondary sales but also causes greater swings in revenues when the market or hydro supply changes. Because secondary revenue uncertainty is one of the largest components of BPA's risk, the approach taken to manage it will have a large impact on the level of the FY 2007-2009 power rate, or its volatility, or both. BPA has customarily relied on financial reserves, which serve as a cushion to help manage the volatility of secondary revenues. Although the level of reserves that will be available for mitigating secondary revenue risk and other risks in FY 2007-2009 is still very uncertain, the expected value of these reserves is only $180 million going into FY 2007 (as of March 2005). That level is insufficient to manage the range of secondary market swings possible with the sustained high gas prices the markets are forecasting.

Key criteria BPA is seeking to meet in a risk management approach include meeting the established 3-year Treasury Payment Probability (TPP) standard of 92.6 percent, increasing PBL Minimum Liquidity Reserves to $100 million, and using only PBL reserves, revenues and risks in calculating the TPP except when the Administrator can forecast having additional reserves temporarily available. To meet these standards and cover the volatility, BPA's preliminary forecast shows it would need an additional $500 million per year in rates in order to set a flat, fixed rate without any adjustments during the rate period. This would lead to unacceptably high rates. On the other hand, if the volatility in secondary revenues could be covered by an adjustable rate, the need for large reserves could be significantly reduced, and the overall power rate could also be reduced. BPA did not propose a particular approach to risk management in the PFR but instead laid out a variety of options available to help mitigate risk and bring down the rate impact of risk management.

Though the regional discussion of this topic is just starting, some key views expressed by one or more customers to date are:

- Some customers have indicated a willingness to have an adjustable rate, if it results in a lower "effective" rate.
- Several customers have said they are much more comfortable with adjustment mechanisms that are automatic, clearly defined, and based on factors beyond BPA's control.
- Treat the variability of IOU benefits as a hedge against the variability of secondary revenues.
- Do not return to the established TPP standard for the FY 2007-2009 period, or do so on a phased-in basis.
- Review the need for an increase in minimum liquidity reserve, and/or phase-in this increase.
- In calculating TPP, recognize the availability of TBL reserves.
- Stepped rates
- Other cash management tools.

It is premature for BPA to respond to these comments now, since the regional discussion of risk management in BPA power rates is ongoing. BPA will work closely with its customers and others to find the best risk management approach from among the many candidates.

Summary of Comments Received on Proposed PFR Forecast

- BPA should not establish a high base rate to cover all risk.
- BPA should separate risk of program increases from hydro risk; implement a Cost Recovery Adjustment Clause (CRAC) with specific parameters.
- BPA needs an effective cost recovery mechanism to ensure meeting the F&W goal.
- Use CRACs rather than build up a huge reserve.
- Slice customers essentially self-insure risk. How about letting all customers self-insure.
- Use conditional budgeting, with a basic budget and a list of things you will do if revenues are better than expected.
- Delay increasing the liquidity reserve. Apply BPA total reserves in modeling, not just PBL. Keep TPP at 80 percent for first year of rate period.
- The TPP of 92.6 percent came from a 10-year old plan. This does not tell us where we should go with risk.
- Costs are a way to meet risk; start looking today at where you could cut costs. Consider a line of credit from the U.S. Treasury.
- Open to assuming less surplus revenue in base rates if there is a rebate mechanism; some rate adjustment mechanism may be appropriate for costs outside BPA's control.
- BPA could commit to carry a portion of the risk on the expense side.
- It would be a loss if the first response to risk is cutting budgets for conservation, renewables and F&W.
- Work to ensure you are not overstating risk; find a balance between customer and BPA holding funds for risk; revisit the recommendations made in the 10-year plan to see if they are appropriate.
- Establish budget category of unidentified cost reductions to close gap between implied rate and rate after risk target. Set the lowest initial rate in exchange for rate variability.
- A well-constructed surcharge can correct for secondary revenue variability.
- Give policy makers an opportunity to talk about risk before the rate case.
- Risk should be a partnership; put conditional budgeting back on the table for discussion.

Final Report Decisions:

Risk mitigation will be a widely debated topic in the FY 2007-2009 power rate case. BPA is acutely aware of the concern customers have on the size and magnitude of this category and shares the concern and will do everything it can to work with rate case participants to address this concern while meeting BPA's mission and objectives. A request from PFR participants for a more policy-level discussion of the topic before the rate case was met through a policy-level workshop held on June 23, with another one likely to be held in early September 2005.

BPA has examined carefully the concept of "contingent budgeting" or similar mechanisms by which expenses are adjusted on short notice in response to fluctuation in water conditions and secondary revenues. To have significant risk mitigation value, such expense adjustments would have to be made on short notice (2 or 3 months) and be in the tens of millions of dollars in magnitude. BPA reviewed each component of its cost structure for such opportunities and concluded that such opportunities are very limited, that the administrative costs of instituting it would be high since it would involve multiple parties in addition to BPA, and that negotiation of such cost flexibility with other parties would need to contemplate both increases and decreases in expenses in response to financial conditions. Moreover, it's an expensive way to operate programs given that the revenue variability on BPA's system would suggest changing funding levels on a regular basis up and down. For these reasons BPA does not plan to institute conditional budgeting. However, as addressed in each section of this PFR report, BPA does plan to review and potentially revise a number of specific cost components before preparing its final power rate proposal next year in hopes of identifying additional cost reductions over the next 8 months.

As noted previously, risk mitigation issues are not decided in the PFR. We will use PFR comments to inform our discussions of and decisions on risk mitigation assumptions that will be incorporated into the power initial power rate proposal. Those assumptions are subject to debate in the rate case process.

Final PFR Report FY 2007-2009 Forecast Levels

	EXPENSE	CAPITAL
BPA's PFR Final Decisions	**Final PFR FY 2007-2009 Average (Reductions)/ Increases**	**Final PFR FY 2007-2009 Average (Reductions)/ Increases**
PFR Decision Areas		
Remove Telemetering costs from Transmission Forecast	($0.8 M/year)	
Remove forecast of Calpine from FY 2007-2008 in Renewables Forecast ($31 M/year for FY 2007-2008)	($21 M/year)	
Revise wind contract output forecast	($4 M/year)	
Include facilitation forecast for FY 2007-2008 in Renewables Forecast ($5.5 M FY 2007, $11 M FY2008)	$6 M/year	
Include renewable rate credit in Renewables Forecast	$6 M/year	
Include TCI cost to Internal Operations Charged to Power Forecast	$1.3 M/year	
Include efficiencies forecast for Internal Operations Charged to Power Forecast	($8 M/year)	
Include reduced funding for WECC/NERC compliance in Corps/Reclamation Forecast	($1.5 M/year)	
Reduce O&M costs per Draft Long Range Plan in CGS forecast	($22 M/year)	
Increase CGS decommissioning trust fund contribution	$1 M/year	
Increase Integrated Program Forecast for F&W	$4 M/year	
Reduce US Fish & Wildlife Service Spending Level	($0.3 M/year)	
Include forecast updates for Environmental Requirements, Transmission Third Party GTA Wheeling and misc.	($13 M/yr)	
Remove Spokane Settlement amount in forecast	($6 M/year)	
Subtotal PFR Decision (Reductions)/Increases	**($58 M/year)**	**$0 M/year**
Rate Case and Other Decision Areas		
Debt Finance CGS Capital (net reduction)	($13 M/year)	
Adopt different CRFM schedule	($5 M/year)	
Change Conservation Amortization Schedule to 5 years	($10 M/year)	
Include Interest Income on cash balances from BPA fund	($10 M/year)	
Subtotal Est. Debt Management Reductions	**($38 M/year)**	
Grand Total	**($96 M/year)**	**$0 M/year**

Summary Table Incorporated Into BPA's Financials for PFR Final Report:

		FY 2002-2006 Average Expense	FY 2002-2006 Average Capital	PFR Base FY 2007-2009 Average Expense	PFR Base FY 2007-2009 Average Capital	PFR Draft Closeout Letter Average Expense	PFR Draft Closeout Letter Average Capital	PFR Final Report Average Expense	PFR Final Report Average Capital	PFR Delta Base to Final Expense	PFR Delta Base to Final Capital
1	Long-Term Generating Projects	$ 28	$ -	$ 25	$ -	$ 25	$ -	$ 25	$ -	$ -	$ -
2	Renewables Program (Expense Only) Removed Geothermal forecast FY07-08 - ($21 M/yr) Revise wind forecast FY07-09 - ($4 M/yr) Added facilitation budget FY07-08 - $6 M/yr Added renewable rate credit FY07-09 - $6 M/yr	$ 22	$ -	$ 56	$ -	$ 61	$ -	$ 42	$ -	$ (13)	$ -
3	Conservation Program (Expense Only)	$ 66	$ 27	$ 71	$ 32	$ 70	$ 28	$ 71	$ 32	$ -	$ -
4	Internal Operations Charged to Power Rates Included forecast for Process Improvements - ($8 M/yr) Included TCI forecast - $1.3 M/yr	$ 107	$ -	$ 116	$ -	$ 110	$ -	$ 110	$ -	$ (6)	$ -
5	Other Removed Spokane Settlement Forecast - ($6 M/yr) Updated Environmental Benefits Forecast - ($7 M/yr) Reduced US Fisheris Forecast - ($300 K/yr) Misc. Updates - ($1 M/yr)	$ 83	$ -	$ 120	$ -	$ 105	$ -	$ 105	$ -	$ (15)	$ -
6	Fish & Wildlife Direct Program (Integrated Program) Increased Integrated Program Forecast - $5 M/yr	$ 139	$ 20	$ 139	$ 36	$ 143	$ 36	$ 143	$ 36	$ 4	$ -
7	Transmission Purchases, and Reserve/Ancillary Services Removed Telemetering Forecast - ($800 K/yr) Updated 3rd Party GTA Wheeling Forecast - ($4 M/yr)	$ 171	$ -	$ 189	$ -	$ 184	$ -	$ 184	$ -	$ (5)	$ -
8	Settlement Payments to Residential & Small Farm Consumers of IOUs 1/	$ 375	$ -	$ 323	$ -	$ 323	$ -	$ 323	$ -	$ -	$ -
9	Corps and Reclamation O&M for Hydro Projects Reduced WECC/NERC complicance forecast - ($1.5 M/yr)	$ 196	$ 110	$ 242	$ 138	$ 240	$ 138	$ 240	$ 138	$ (2)	$ -
10	Columbia Generating Station O&M for Nuclear Plant Reduced O&M forecast per Draft Long Range Plan - ($22 M/yr) Increased contribution to Decomissioning Fund - $1 M/yr	$ 215	N/A	$ 284	$ -	$ 262	$ -	$ 263	$ -	$ (21)	$ -
11	Debt Management Debt Financed CGS Capital - ($13 M/yr) 2/ Adopted different CRFM schedule ($5 M/yr) Changed Conservation Augmentation Schedule to 5 years - ($10 M/yr)	$ 892	$ -	$ 1,003	$ -	$ 965	$ -	$ 965	$ -	$ (38)	$ -
12	Power Purchases	$ 559	$ -	$ 107	$ -	$ 107	$ -	$ 107	$ -	$ -	$ -
13	**Total**	**$ 2,853**	**$ 157**	**$ 2,674**	**$ 206**	**$ 2,594**	**$ 202**	**$ 2,577**	**$ 206**	**$ (96)**	**$ -**

1/ Total includes 900 aMW of Monetary Benefit ($139 M/yr average), and approximately 618 aMW of load augmentation (BPA power buyback) ($235 M/yr average)
2/ Total includes net impact of CGS capital decision. Final rate case outcome will show a reduction in CGS O&M and an increase in Debt Management.

BPA's Financial Disclosure Information

* All FY 2005-2009 information cannot be found in BPA-approved Agency Financial Information but is provided for discussion or exploratory purposes only as projections of program activity levels, etc.

* All FY 1997-2004 information is consistent with audited actuals that contain BPA-approved Agency Financial Information.

APPENDIX B

REPAYMENT PROGRAM TABLES

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DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table 10 shows the amortization results from the Generation repayment studies for FY 2007 - 2009, summarized by bonds, appropriations and irrigation due and discretionary, by year.

Tables 11 through 13, A through G, show the results from the Generation repayment studies for FY 2007 through 2009, respectively, using revenues from current rates. Table 14 provides the application of amortization through the repayment period for generation based upon the revenues forecast using current rates.

Tables 11A through 13A display the repayment program results for generation for FY 2007 through 2009. The first column shows the applicable fiscal year. The second column shows the total investment costs of the generating projects through the cost evaluation period. *See,* Documentation, Chapter 4, WP-07-FS-BPA-02A. In the third column, forecasted replacements required to maintain the system are displayed through the repayment period. *See,* Documentation, Chapter 10, WP-07-FS-BPA-02A. The fourth column shows the cumulative dollar amount of the generation investment placed in service. This is comprised of historical plant-in-service, planned replacements and additions to plant through the cost evaluation period, and replacements from the end of the cost evaluation period to the end of the repayment study period. For these studies all additional plant is assumed to be financed either by appropriations or bonds.

The next two columns show scheduled amortization payments for each year of the repayment period. Discretionary amortization shows generation amortization payments made before the due dates of each particular obligation. Unamortized investments, shown in column 7, are determined by taking the previous year's unamortized amount, adding any replacements, subtracting amortization and subtracting discretionary amortization. Columns 8, 9, and 10 show a similar calculation of predetermined amortization payments and the unamortized amount of irrigation assistance for each year of the repayment period. Irrigation assistance is assigned 100 percent to generation.

Tables 11B-13B display planned principal payments by fiscal year for Federal generation obligations. Shown on these tables are the principal payments associated with the appropriations of the COE and Reclamation, and BPA bonds.

Tables 11C-13C show the component of the capitalized contractual obligations associated with payment of principal. Included is the stream of payments associated with a long-term, relatively fixed, energy resource acquisition contract that will not be capitalized. The capitalized contractual obligations are 100 percent generation-related.

Tables 11D-13D show the planned interest payments by fiscal year for Federal generation obligations. Shown on these tables are the interest payments associated with the appropriations of the COE and Reclamation, and BPA bonds.

Tables 11E-13E show the component of the capitalized contractual obligations associated with payment of interest expense. Included is the stream of payments associated with a long-term, relatively fixed, energy resource acquisition contract that will not be capitalized. The capitalized contractual obligations are 100 percent generation-related.

Tables 11F-13F show a summary of all Federal and capitalized contract generation principal and interest payments.

Tables 11G-13G compare the schedule of unamortized Federal generation obligations resulting from the Generation repayment studies to those obligations that are due and must be paid for each year of the repayment period. Column 2 shows unamortized obligations and is identical to the data shown in Column 7 of Tables 11A-13A. Column 3 shows obligations that are due for each year. It should be noted that unamortized obligations are always less than the term schedule, indicating that planned repayments are in excess of repayment obligations, thereby satisfying repayment requirements. The total of Unamortized Investment need not necessarily be zero at the end of the repayment period because of the replacements occurring subsequent to the cost evaluation period.

Table 11 lists by year through the 50-year repayment period the application of the generation amortization payments, consistent with the revised repayment studies, by project. The projected annual amortization payments on the generation obligations are identified by the project name, in-service date, due date, and interest rate. The amount of the obligation is shown as both the original gross amount due and the net amount after all prior amortization payments.

Table 10

APPLICATION OF AMORTIZATION
REPAYMENT STUDY FOR INITIAL PROPOSAL
FY 2007 - 2009
($000s)

Maturing/Due		
Bonds		
	2007	68,357
	2008	104,300
	2009	59,220
		231,877
Appropriations		
	2007	9,220
	2008	0
	2009	0
		9,220
Irrigation Assistance		
	2008	2,950
	2009	6,590
		9,540
	TOTAL	**250,637**

Scheduled But Not Yet Due		
Bonds		
	2007	0
	2008	0
	2009	0
		0
Appropriations		
	2007	92,696
	2008	77,961
	2009	110,637
		281,294
	TOTAL	**281,294**

Total by Year		
Bonds		
	2007	68,357
	2008	104,300
	2009	59,220
		231,877
Appropriations		
	2007	101,916
	2008	77,961
	2009	110,637
		290,514
Irrigation Assistance		
	2008	2,950
	2009	6,590
		9,540
Total		
	2007	170,273
	2008	185,211
	2009	176,447
		531,931

Table 11A: Generation Investments Placed in Service FY 2007 ($000s)

	Investment Placed in Service						Irrigation Assistance		
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment	Cumulative Amount in Serivce	Amortization	Unamortized Amount
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
09/30/2004	3,879,119.71	45,747.00	3,924,866.71	-	-	3,924,866.71	668,200.00	-	668,200.00
09/30/2005	312,014.00	-	4,236,880.71	220,163.00	51,134.00	3,965,583.71	668,200.00	-	668,200.00
09/30/2006	246,528.00	-	4,483,408.71	178,262.00	83,214.00	3,950,635.71	668,200.00	-	668,200.00
09/30/2007	289,244.00	-	4,772,652.71	77,577.00	92,695.53	4,069,607.18	668,200.00	-	668,200.00
09/30/2008	363,171.00	-	5,135,823.71	104,300.00	14,461.48	4,314,016.70	668,200.00	2,950.00	665,250.00
09/30/2009	-	132,082.00	5,267,905.71	59,220.00	92,779.83	4,294,098.87	668,200.00	6,590.00	658,660.00
09/30/2010	-	123,554.00	5,391,459.71	30,068.00	110,960.68	4,276,624.19	675,142.00	-	665,602.00
09/30/2011	-	115,478.00	5,506,937.71	66,500.00	67,340.00	4,258,262.19	681,708.00	-	672,168.00
09/30/2012	-	107,833.00	5,614,770.71	32,747.48	13,267.76	4,320,079.95	685,184.00	706.00	674,938.00
09/30/2013	-	100,692.00	5,715,462.71	145,300.00	1,795.47	4,273,676.48	704,977.00	44,178.00	650,553.00
09/30/2014	-	101,059.00	5,816,521.71	38,650.00	163,205.56	4,172,879.92	742,507.00	42,744.00	645,339.00
09/30/2015	-	101,445.00	5,917,966.71	-	169,512.23	4,104,812.69	747,614.00	95,210.59	555,235.41
09/30/2016	-	101,828.00	6,019,794.71	-	0.01	4,206,640.68	753,008.00	61,191.25	499,438.16
09/30/2017	-	102,273.00	6,122,067.71	-	-	4,308,913.68	788,261.00	3.16	534,688.00
09/30/2018	-	102,776.00	6,224,843.71	-	114,186.75	4,297,502.93	839,448.00	22,943.00	562,932.00
09/30/2019	-	103,335.00	6,328,178.71	-	340,379.29	4,060,458.64	850,350.00	57,816.00	516,018.00
09/30/2020	-	103,944.00	6,432,122.71	10,000.00	372,605.44	3,781,797.20	871,608.00	32,731.00	504,545.00
09/30/2021	-	104,603.00	6,536,725.71	36,000.00	384,346.13	3,466,054.07	910,815.00	14,920.00	528,832.00
09/30/2022	-	105,307.00	6,642,032.71	36,000.00	407,087.97	3,128,273.10	949,864.00	13,318.00	554,563.00
09/30/2023	-	93,738.00	6,735,770.71	36,000.00	429,790.82	2,756,220.28	978,944.00	9,613.00	574,030.00
09/30/2024	-	83,581.00	6,819,351.71	-	485,288.47	2,354,512.81	1,020,750.00	21,148.00	594,688.00
09/30/2025	-	74,621.00	6,893,972.71	-	536,694.69	1,892,439.12	1,040,787.00	11,234.00	603,491.00
09/30/2026	-	66,724.00	6,960,696.71	-	559,052.81	1,400,110.31	1,074,015.00	18,128.00	618,591.00
09/30/2027	-	59,766.00	7,020,462.71	-	597,017.45	862,858.86	1,106,243.00	5,385.00	645,434.00
09/30/2028	-	53,571.00	7,074,033.71	3,181.00	630,346.40	282,902.46	1,139,629.00	12,719.00	666,101.00
09/30/2029	-	48,097.00	7,122,130.71	-	85,999.46	245,000.00	1,184,426.00	194,672.00	516,226.00
09/30/2030	-	43,307.00	7,165,437.71	-	43,307.00	245,000.00	1,214,389.00	-	546,189.00
09/30/2031	-	39,045.00	7,204,482.71	-	39,045.00	245,000.00	1,244,352.00	-	576,152.00
09/30/2032	-	35,283.00	7,239,765.71	-	35,283.00	245,000.00	1,289,149.00	-	620,949.00
09/30/2033	-	50,409.00	7,290,174.71	-	50,409.00	245,000.00	1,329,573.00	-	661,373.00
09/30/2034	-	50,868.00	7,341,042.71	-	50,868.00	245,000.00	1,369,997.00	-	701,797.00
09/30/2035	-	51,369.00	7,392,411.71	20,000.00	51,369.00	225,000.00	1,399,204.00	-	731,004.00
09/30/2036	-	51,855.00	7,444,266.71	25,000.00	51,855.00	200,000.00	1,427,753.00	-	759,553.00
09/30/2037	-	52,381.00	7,496,647.71	-	52,381.00	200,000.00	1,456,461.00	-	788,261.00
09/30/2038	-	52,944.00	7,549,591.71	25,000.00	52,944.00	175,000.00	1,485,771.00	-	817,571.00
09/30/2039	-	53,546.00	7,603,137.71	25,000.00	53,546.00	150,000.00	1,515,082.00	-	846,882.00
09/30/2040	-	54,129.00	7,657,266.71	50,000.00	54,129.00	100,000.00	1,548,917.00	-	880,717.00
09/30/2041	-	54,747.00	7,712,013.71	-	54,747.00	100,000.00	1,582,753.00	-	914,553.00
09/30/2042	-	55,399.00	7,767,412.71	60,000.00	55,399.00	40,000.00	1,617,447.00	-	949,247.00
09/30/2043	-	52,192.00	7,819,604.71	40,000.00	52,192.00	0.00	1,652,142.00	-	983,942.00
09/30/2044	-	49,175.00	7,868,779.71	-	49,175.00	0.00	1,685,083.00	-	1,016,883.00

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11A: Generation Investments Placed in Service FY 2007 ($000s)

	Investment Placed in Service						Irrigation Assistance		
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment	Cumulative Amount in Serivce	Amortization	Unamortized Amount
09/30/2045	-	46,388.00	7,915,167.71	-	46,388.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2046	-	43,772.00	7,958,939.71	-	43,772.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2047	-	41,323.00	8,000,262.71	(0.00)	41,323.00	0.01	1,718,024.00	-	1,049,824.00
09/30/2048	-	39,032.00	8,039,294.71	-	39,032.00	0.01	1,718,024.00	-	1,049,824.00
09/30/2049	-	35,217.00	8,074,511.71	0.00	35,217.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2050	-	31,823.00	8,106,334.71	0.01	31,823.00	(0.01)	1,718,024.00	-	1,049,824.00
09/30/2051	-	28,831.00	8,135,165.71	(0.00)	28,831.00	(0.01)	1,718,024.00	-	1,049,824.00
09/30/2052	-	26,183.00	8,161,348.71	(0.00)	26,183.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2053	-	41,003.00	8,202,351.71	0.00	41,003.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2054	-	41,553.00	8,243,904.71	(0.00)	41,553.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2055	-	42,132.00	8,286,036.71	-	42,132.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2056	-	42,740.00	8,328,776.71	-	42,740.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2057	-	43,334.00	8,372,110.71	-	43,334.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2058	-	43,955.00	8,416,065.71	-	43,955.00	(0.00)	1,718,024.00	-	1,049,824.00
Total	**$5,090,076.71**	**$3,325,989.00**	**-**	**$1,318,968.48**	**$7,097,097.23**	**-**	**-**	**$668,200.00**	**-**

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11B: Federal Principal Payments FY 2007 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation	
Date	Bonds (1)	Appropriations	Appropriations	Irrigation Amortization
09/30/2005	116,990.00	154,307.00	-	-
09/30/2006	125,062.00	136,407.00	7.00	-
09/30/2007	68,357.00	101,686.53	229.00	-
09/30/2008	104,300.00	14,461.48	-	2,950.00
09/30/2009	59,220.00	91,912.83	867.00	6,590.00
09/30/2010	30,068.00	110,960.68	-	-
09/30/2011	66,500.00	67,340.00	-	-
09/30/2012	32,000.00	14,015.24	-	706.00
09/30/2013	145,300.00	1,795.47	-	44,178.00
09/30/2014	38,650.00	155,446.77	7,758.79	42,744.00
09/30/2015	-	133,070.02	36,442.21	95,210.59
09/30/2016	-	0.01	-	61,191.25
09/30/2017	-	-	-	3.16
09/30/2018	-	64,819.75	49,367.00	22,943.00
09/30/2019	-	239,356.29	101,023.00	57,816.00
09/30/2020	10,000.00	270,730.44	101,875.00	32,731.00
09/30/2021	36,000.00	235,887.13	148,459.00	14,920.00
09/30/2022	59,411.66	302,742.31	80,934.00	13,318.00
09/30/2023	157,588.34	308,202.48	-	9,613.00
09/30/2024	-	485,288.47	-	21,148.00
09/30/2025	-	536,694.69	-	11,234.00
09/30/2026	64,365.45	494,687.36	-	18,128.00
09/30/2027	314,848.96	282,168.49	-	5,385.00
09/30/2028	13,435.59	539,068.28	81,023.53	12,719.00
09/30/2029	-	85,999.46	-	194,672.00
09/30/2030	-	43,307.00	-	-
09/30/2031	-	39,045.00	-	-
09/30/2032	-	35,283.00	-	-
09/30/2033	-	50,409.00	-	-
09/30/2034	-	50,868.00	-	-

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11B: Federal Principal Payments FY 2007 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation	
Date	Bonds (1)	Appropriations	Appropriations	Irrigation Amortization
09/30/2035	20,000.00	51,369.00	-	-
09/30/2036	25,000.00	51,855.00	-	-
09/30/2037	-	52,381.00	-	-
09/30/2038	25,000.00	52,944.00	-	-
09/30/2039	25,000.00	53,546.00	-	-
09/30/2040	50,000.00	54,129.00	-	-
09/30/2041	-	54,747.00	-	-
09/30/2042	60,000.00	55,399.00	-	-
09/30/2043	40,000.00	52,192.00	-	-
09/30/2044	-	49,175.00	-	-
09/30/2045	-	46,388.00	-	-
09/30/2046	-	43,772.00	-	-
09/30/2047	-	41,323.00	-	-
09/30/2048	-	39,032.00	-	-
09/30/2049	-	35,217.00	-	-
09/30/2050	-	31,823.01	-	-
09/30/2051	-	28,831.00	(0.00)	-
09/30/2052	-	26,183.00	-	-
09/30/2053	-	41,003.00	-	-
09/30/2054	-	41,553.00	-	-
09/30/2055	-	42,132.00	-	-
09/30/2056	-	42,740.00	-	-
09/30/2057	-	43,334.00	-	-
09/30/2058	-	43,955.00	-	-
Total	**$1,687,097.00**	**$6,120,983.18**	**$607,985.53**	**$668,200.00**

(1) Net of interest income and AFUDC.
(2) Includes payments for Lower Snake Fish and Wildlife.

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2024 COST EVALUATION PERIOD

Table 11C: Component of Capitalized Contract Principal Payments FY 2007 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2005	47,949.00	3,824.58	7,693.33	59,466.92
2006	213,983.69	7,465.83	8,880.00	230,329.52
2007	298,736.89	7,837.50	9,300.83	315,875.22
2008	339,277.05	7,512.08	9,695.83	356,484.96
2009	312,421.28		10,160.83	322,582.11
2010	352,757.47		10,646.67	363,404.14
2011	384,357.34		11,148.33	395,505.67
2012	486,964.24		11,699.17	498,663.41
2013	361,192.83		12,276.67	373,469.50
2014	335,813.30		12,895.00	348,708.30
2015	360,962.84		8,817.50	369,780.34
2016	581,956.49		8,943.33	590,899.83
2017	665,732.02		9,402.50	675,134.52
2018	486,499.53		9,872.50	496,372.03
2019	33,482.75		10,366.67	43,849.42
2020	35,776.50		10,885.83	46,662.33
2021	38,227.50		11,435.00	49,662.50
2022	40,845.75		12,014.17	52,859.92
2023	43,644.00		13,028.33	56,672.33
2024	46,634.00		13,682.50	60,316.50
2025	49,828.00		352.50	50,180.50
2026	53,241.50			53,241.50
2027	56,888.75			56,888.75
2028	60,785.25			60,785.25
2029	64,948.75			64,948.75
2030	69,398.25			69,398.25
2031	74,151.50			74,151.50
2032	79,231.00			79,231.00
2033	84,658.50			84,658.50
2034	90,458.00			90,458.00
2035	96,654.25			96,654.25
2036	103,274.75			103,274.75
2037	110,349.00			110,349.00
2038	117,908.00			117,908.00
2039	125,984.25			125,984.25
2040	134,614.50			134,614.50
2041	143,835.75			143,835.75
2042	153,688.50			153,688.50
2043	164,216.00			164,216.00
2044	175,465.25			175,465.25
2045	187,484.50			187,484.50
2046	200,326.75			200,326.75

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2024 COST EVALUATION PERIOD

Table 11C: Component of Capitalized Contract Principal Payments FY 2007 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2047	214,049.00			214,049.00
2048	228,711.75			228,711.75
2049	244,378.50			244,378.50
2050	261,118.25			261,118.25
2051	279,004.50			279,004.50
2052	298,116.50			298,116.50
2053	318,538.00			318,538.00
2054	250,970.25			250,970.25

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11D: Federal Interest Payments FY 2007 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation
Date	Generation and Conserv. Bonds (1)	Generation Appropriations	Generation Appropriations
09/30/2005	30,873.04	170,668.62	42,442.41
09/30/2006	36,288.21	166,706.22	42,442.41
09/30/2007	51,050.19	158,179.22	42,441.92
09/30/2008	68,661.45	155,231.75	42,426.00
09/30/2009	70,743.89	162,442.58	42,426.00
09/30/2010	67,006.75	164,828.08	42,363.49
09/30/2011	65,637.19	165,276.39	42,363.49
09/30/2012	64,441.07	168,328.22	42,363.49
09/30/2013	59,268.77	174,678.92	42,363.49
09/30/2014	49,499.96	181,417.56	42,363.49
09/30/2015	46,850.78	177,179.79	41,807.96
09/30/2016	51,673.35	174,583.82	39,198.71
09/30/2017	52,926.50	181,528.49	39,198.71
09/30/2018	49,597.31	188,503.51	39,198.71
09/30/2019	43,592.44	190,878.20	35,668.96
09/30/2020	43,595.87	180,811.68	28,445.81
09/30/2021	43,059.32	168,543.42	21,161.75
09/30/2022	42,094.64	158,811.41	10,546.92
09/30/2023	42,758.05	144,347.23	4,760.13
09/30/2024	26,160.69	129,720.76	4,760.13
09/30/2025	25,835.03	102,324.31	4,760.13
09/30/2026	28,247.64	70,810.89	4,760.13
09/30/2027	31,978.63	41,623.79	4,760.13
09/30/2028	1,445.81	28,062.73	4,760.13
09/30/2029	308.26	1,942.49	-
09/30/2030	315.03	-	-
09/30/2031	322.23	-	-
09/30/2032	329.95	-	-
09/30/2033	338.20	-	-
09/30/2034	347.02	-	-

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11D: Federal Interest Payments FY 2007 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation
Date	Generation and Conserv. Bonds (1)	Generation Appropriations	Generation Appropriations
09/30/2035	356.43	-	-
09/30/2036	(855.80)	-	-
09/30/2037	(2,618.28)	-	-
09/30/2038	(2,606.80)	-	-
09/30/2039	(4,312.11)	-	-
09/30/2040	(6,016.56)	-	-
09/30/2041	(9,285.93)	-	-
09/30/2042	(9,270.96)	-	-
09/30/2043	(13,314.41)	-	-
09/30/2044	(15,919.96)	-	-
09/30/2045	(15,901.71)	-	-
09/30/2046	(15,882.21)	-	-
09/30/2047	(15,861.36)	-	-
09/30/2048	(15,839.08)	-	-
09/30/2049	(15,815.28)	-	-
09/30/2050	(15,789.85)	-	-
09/30/2051	(15,762.69)	-	-
09/30/2052	(15,733.65)	-	-
09/30/2053	(15,702.62)	-	-
09/30/2054	(17,783.49)	-	-
09/30/2055	(24,099.40)	-	-
09/30/2056	(24,099.40)	-	-
09/30/2057	(24,099.40)	-	-
09/30/2058	(24,099.40)	-	-
Total	**$774,933.35**	**$3,607,430.08**	**$707,784.50**

(1) Net of interest income and AFUDC.
(2) Includes payments for Lower Snake Fish and Wildlife.

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2024 COST EVALUATION PERIOD

Table 11E: Component of Capitalized Contract Interest Payments FY 2007 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2005	256,448.70	562.54	8,073.46	265,084.70
2006	277,259.46	1,140.77	7,672.19	286,072.42
2007	284,108.52	767.48	7,268.30	292,144.29
2008	265,910.30	375.60	8,494.94	274,780.84
2009	253,568.23		8,520.64	262,088.86
2010	232,051.46		8,060.21	240,111.67
2011	208,578.23		7,534.04	216,112.27
2012	191,217.51		6,976.67	198,194.18
2013	171,261.56		6,378.35	177,639.91
2014	146,342.71		5,750.07	152,092.78
2015	113,230.58		5,208.62	118,439.20
2016	96,467.52		4,762.53	101,230.05
2017	65,670.07		4,301.01	69,971.08
2018	104,136.20		3,816.12	107,952.32
2019	303,249.94		3,306.96	306,556.90
2020	301,103.69		2,772.31	303,876.01
2021	298,810.42		2,210.78	301,021.20
2022	296,360.04		1,620.86	297,980.89
2023	293,741.82		990.91	294,732.73
2024	290,944.24		340.77	291,285.01
2025	287,955.00		9.17	287,964.17
2026	284,761.03			284,761.03
2027	281,348.25			281,348.25
2028	277,701.68			277,701.68
2029	273,805.35			273,805.35
2030	269,642.13			269,642.13
2031	265,193.70			265,193.70
2032	260,440.59			260,440.59
2033	255,361.88			255,361.88
2034	249,935.28			249,935.28
2035	244,136.92			244,136.92
2036	237,941.38			237,941.38
2037	231,321.47			231,321.47
2038	224,248.10			224,248.10
2039	216,690.19			216,690.19
2040	208,614.60			208,614.60
2041	199,985.81			199,985.81
2042	190,765.94			190,765.94
2043	180,914.51			180,914.51
2044	170,388.26			170,388.26
2045	159,140.94			159,140.94
2046	147,123.19			147,123.19

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2024 COST EVALUATION PERIOD

Table 11E: Component of Capitalized Contract Interest Payments FY 2007 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2047	134,282.24			134,282.24
2048	120,561.70			120,561.70
2049	105,901.28			105,901.28
2050	90,236.62			90,236.62
2051	73,498.94			73,498.94
2052	55,614.75			55,614.75
2053	36,505.48			36,505.48
2054	16,087.19			16,087.19

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11F: Summary of Payments FY 2007 ($000s)

	Principal			Interest		
Date	Generation Payment	Capitalized Contracts Payment	Total Principal Payment	Generation Payment	Capitalized Contracts Payment	Total Interest Payment
09/30/2005	271,297.00	59,466.92	330,763.92	243,984.07	265,084.70	509,068.77
09/30/2006	261,476.00	230,329.52	491,805.52	245,436.84	286,072.42	531,509.26
09/30/2007	170,272.53	315,875.22	486,147.75	251,671.33	292,144.29	543,815.62
09/30/2008	121,711.48	356,484.96	478,196.44	266,319.20	274,780.84	541,100.04
09/30/2009	158,589.83	322,582.11	481,171.94	275,612.47	262,088.86	537,701.33
09/30/2010	141,028.68	363,404.14	504,432.82	274,198.32	240,111.67	514,309.99
09/30/2011	133,840.00	395,505.67	529,345.67	273,277.07	216,112.27	489,389.34
09/30/2012	46,721.24	498,663.41	545,384.65	275,132.78	198,194.18	473,326.96
09/30/2013	191,273.47	373,469.50	564,742.97	276,311.18	177,639.91	453,951.09
09/30/2014	244,599.56	348,708.30	593,307.86	273,281.01	152,092.78	425,373.79
09/30/2015	264,722.82	369,780.34	634,503.16	265,838.53	118,439.20	384,277.73
09/30/2016	61,191.26	590,899.83	652,091.09	265,455.88	101,230.05	366,685.93
09/30/2017	3.16	675,134.52	675,137.68	273,653.70	69,971.08	343,624.78
09/30/2018	137,129.75	496,372.03	633,501.78	277,299.53	107,952.32	385,251.85
09/30/2019	398,195.29	43,849.42	442,044.71	270,139.60	306,556.90	576,696.50
09/30/2020	415,336.44	46,662.33	461,998.77	252,853.36	303,876.01	556,729.37
09/30/2021	435,266.13	49,662.50	484,928.63	232,764.49	301,021.20	533,785.69
09/30/2022	456,405.97	52,859.92	509,265.89	211,452.97	297,980.89	509,433.86
09/30/2023	475,403.82	56,672.33	532,076.15	191,865.41	294,732.73	486,598.14
09/30/2024	506,436.47	60,316.50	566,752.97	160,641.58	291,285.01	451,926.59
09/30/2025	547,928.69	50,180.50	598,109.19	132,919.47	287,964.17	420,883.64
09/30/2026	577,180.81	53,241.50	630,422.31	103,818.66	284,761.03	388,579.69
09/30/2027	602,402.45	56,888.75	659,291.20	78,362.55	281,348.25	359,710.80
09/30/2028	646,246.40	60,785.25	707,031.65	34,268.67	277,701.68	311,970.35
09/30/2029	280,671.46	64,948.75	345,620.21	2,250.75	273,805.35	276,056.10
09/30/2030	43,307.00	69,398.25	112,705.25	315.03	269,642.13	269,957.16
09/30/2031	39,045.00	74,151.50	113,196.50	322.23	265,193.70	265,515.93
09/30/2032	35,283.00	79,231.00	114,514.00	329.95	260,440.59	260,770.54
09/30/2033	50,409.00	84,658.50	135,067.50	338.20	255,361.88	255,700.08

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11F: Summary of Payments FY 2007 ($000s)

	Principal			Interest		
Date	**Generation Payment**	**Capitalized Contracts Payment**	**Total Principal Payment**	**Generation Payment**	**Capitalized Contracts Payment**	**Total Interest Payment**
09/30/2034	50,868.00	90,458.00	141,326.00	347.02	249,935.28	250,282.30
09/30/2035	71,369.00	96,654.25	168,023.25	356.43	244,136.92	244,493.35
09/30/2036	76,855.00	103,274.75	180,129.75	(855.80)	237,941.38	237,085.58
09/30/2037	52,381.00	110,349.00	162,730.00	(2,618.28)	231,321.47	228,703.19
09/30/2038	77,944.00	117,908.00	195,852.00	(2,606.80)	224,248.10	221,641.30
09/30/2039	78,546.00	125,984.25	204,530.25	(4,312.11)	216,690.19	212,378.08
09/30/2040	104,129.00	134,614.50	238,743.50	(6,016.56)	208,614.60	202,598.04
09/30/2041	54,747.00	143,835.75	198,582.75	(9,285.93)	199,985.81	190,699.88
09/30/2042	115,399.00	153,688.50	269,087.50	(9,270.96)	190,765.94	181,494.98
09/30/2043	92,192.00	164,216.00	256,408.00	(13,314.41)	180,914.51	167,600.10
09/30/2044	49,175.00	175,465.25	224,640.25	(15,919.96)	170,388.26	154,468.30
09/30/2045	46,388.00	187,484.50	233,872.50	(15,901.71)	159,140.94	143,239.23
09/30/2046	43,772.00	200,326.75	244,098.75	(15,882.21)	147,123.19	131,240.98
09/30/2047	41,323.00	214,049.00	255,372.00	(15,861.36)	134,282.24	118,420.88
09/30/2048	39,032.00	228,711.75	267,743.75	(15,839.08)	120,561.70	104,722.62
09/30/2049	35,217.00	244,378.50	279,595.50	(15,815.28)	105,901.28	90,086.00
09/30/2050	31,823.01	261,118.25	292,941.26	(15,789.85)	90,236.62	74,446.77
09/30/2051	28,831.00	279,004.50	307,835.50	(15,762.69)	73,498.94	57,736.25
09/30/2052	26,183.00	298,116.50	324,299.50	(15,733.65)	55,614.75	39,881.10
09/30/2053	41,003.00	318,538.00	359,541.00	(15,702.62)	36,505.48	20,802.86
09/30/2054	41,553.00	250,970.25	292,523.25	(17,783.49)	16,087.19	(1,696.30)
09/30/2055	42,132.00	-	42,132.00	(24,099.40)	-	(24,099.40)
09/30/2056	42,740.00	-	42,740.00	(24,099.40)	-	(24,099.40)
09/30/2057	43,334.00	-	43,334.00	(24,099.40)	-	(24,099.40)
09/30/2058	43,955.00	-	43,955.00	(24,099.40)	-	(24,099.40)
					-	
Total	**$9,084,265.71**	**$10,199,329.73**	**$19,283,595.44**	**$5,090,147.93**	**$10,307,480.89**	**$15,397,628.82**

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11G: Summary of Federal Outstanding Balance FY 2007 ($000s)

Date	Unamortized Investment	Term Schedule
09/30/2004	3,924,866.71	5,407,769.71
09/30/2005	3,965,583.71	5,454,196.71
09/30/2006	3,950,635.71	5,462,462.71
09/30/2007	4,069,607.18	5,291,205.71
09/30/2008	4,314,016.70	5,287,800.71
09/30/2009	4,294,098.87	5,282,547.71
09/30/2010	4,276,624.19	5,331,197.71
09/30/2011	4,258,262.19	5,325,058.71
09/30/2012	4,320,079.95	5,322,660.71
09/30/2013	4,273,676.48	5,138,052.71
09/30/2014	4,172,879.92	5,175,587.71
09/30/2015	4,104,812.69	5,157,032.71
09/30/2016	4,206,640.68	5,256,156.71
09/30/2017	4,308,913.68	5,292,303.71
09/30/2018	4,297,502.93	5,349,874.71
09/30/2019	4,060,458.64	5,328,437.71
09/30/2020	3,781,797.20	5,313,552.71
09/30/2021	3,466,054.07	5,298,307.71
09/30/2022	3,128,273.10	5,299,885.71
09/30/2023	2,756,220.28	5,184,610.71
09/30/2024	2,354,512.81	5,260,923.71
09/30/2025	1,892,439.12	5,096,054.71
09/30/2026	1,400,110.31	4,926,587.71
09/30/2027	862,858.86	4,875,242.71
09/30/2028	282,902.46	4,712,613.71
09/30/2029	245,000.00	4,503,289.71
09/30/2030	245,000.00	4,543,482.71
09/30/2031	245,000.00	4,540,175.71
09/30/2032	245,000.00	4,368,945.71
09/30/2033	245,000.00	4,120,025.71
09/30/2034	245,000.00	4,170,893.71
09/30/2035	225,000.00	4,154,048.71
09/30/2036	200,000.00	4,205,639.71
09/30/2037	200,000.00	4,185,484.71
09/30/2038	175,000.00	4,219,580.71
09/30/2039	150,000.00	4,273,126.71
09/30/2040	100,000.00	4,304,498.71
09/30/2041	100,000.00	4,337,125.71
09/30/2042	40,000.00	4,379,525.71
09/30/2043	0.00	4,260,364.71
09/30/2044	0.00	4,242,752.71
09/30/2045	0.00	4,200,189.71
09/30/2046	0.00	4,215,112.71
09/30/2047	0.00	4,186,364.76
09/30/2048	0.00	4,225,396.76
09/30/2049	0.00	4,216,613.44
09/30/2050	0.01	4,075,729.94
09/30/2051	0.01	3,864,600.55

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2007 COST EVALUATION PERIOD

Table 11G: Summary of Federal Outstanding Balance FY 2007 ($000s)

Date	Unamortized Investment	Term Schedule
09/30/2052	0.00	3,743,898.16
09/30/2053	0.00	3,563,365.03
09/30/2054	-	3,344,267.00
09/30/2055	-	3,128,651.00
09/30/2056	-	3,033,754.00
09/30/2057	-	2,893,136.00
09/30/2058	-	2,700,603.00
Total	**$89,383,828.52**	**$251,030,769.22**

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2008 COST EVALUATION PERIOD

Table 12A: Generation Investments Placed in Service FY 2008 ($000s)

	Investment Placed in Service							Irrigation Assistance	
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment	Cumulative Amount in Serivce	Amortization	Unamortized Amount
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
09/30/2004	3,879,119.71	45,747.00	3,924,866.71	-	-	3,924,866.71	668,200.00	-	668,200.00
09/30/2005	312,014.00	-	4,236,880.71	220,163.00	51,134.00	3,965,583.71	668,200.00	-	668,200.00
09/30/2006	246,528.00	-	4,483,408.71	178,262.00	83,214.00	3,950,635.71	668,200.00	-	668,200.00
09/30/2007	289,244.00	-	4,772,652.71	77,577.00	92,695.53	4,069,607.18	668,200.00	-	668,200.00
09/30/2008	363,171.00	-	5,135,823.71	104,300.00	77,961.48	4,250,516.70	668,200.00	2,950.00	665,250.00
09/30/2009	223,578.00	-	5,359,401.71	59,220.00	32,537.02	4,382,337.68	668,200.00	6,590.00	658,660.00
09/30/2010	-	126,180.00	5,485,581.71	30,068.00	110,972.02	4,367,477.66	675,142.00	-	665,602.00
09/30/2011	-	117,932.00	5,603,513.71	66,500.00	67,034.26	4,351,875.40	681,708.00	-	672,168.00
09/30/2012	-	110,125.00	5,713,638.71	32,000.00	13,994.55	4,416,005.85	685,184.00	706.00	674,938.00
09/30/2013	-	102,832.00	5,816,470.71	145,300.00	3,306.43	4,370,231.42	704,977.00	44,178.00	650,553.00
09/30/2014	-	103,207.00	5,919,677.71	71,150.00	132,054.23	4,270,234.19	742,507.00	42,744.00	645,339.00
09/30/2015	-	103,601.00	6,023,278.71	-	171,023.48	4,202,811.71	747,614.00	94,541.12	555,904.88
09/30/2016	-	103,993.00	6,127,271.71	-	-	4,306,804.71	753,008.00	61,860.78	499,438.10
09/30/2017	-	104,447.00	6,231,718.71	-	-	4,411,251.71	788,261.00	3.10	534,688.00
09/30/2018	-	104,961.00	6,336,679.71	-	112,493.71	4,403,719.00	839,448.00	22,943.00	562,932.00
09/30/2019	-	105,532.00	6,442,211.71	-	336,941.33	4,172,309.67	850,350.00	57,816.00	516,018.00
09/30/2020	-	106,154.00	6,548,365.71	10,000.00	368,655.77	3,899,807.90	871,608.00	32,731.00	504,545.00
09/30/2021	-	106,827.00	6,655,192.71	36,000.00	379,846.56	3,590,788.34	910,815.00	14,920.00	528,832.00
09/30/2022	-	107,545.00	6,762,737.71	36,000.00	403,123.23	3,259,210.11	949,864.00	13,318.00	554,563.00
09/30/2023	-	95,731.00	6,858,468.71	36,000.00	422,479.09	2,896,462.02	978,944.00	9,613.00	574,030.00
09/30/2024	-	85,358.00	6,943,826.71	36,000.00	443,696.79	2,502,123.23	1,020,750.00	21,148.00	594,688.00
09/30/2025	-	76,207.00	7,020,033.71	-	530,987.25	2,047,342.98	1,040,787.00	11,234.00	603,491.00
09/30/2026	-	68,142.00	7,088,175.71	-	553,530.60	1,561,954.38	1,074,015.00	18,128.00	618,591.00
09/30/2027	-	61,037.00	7,149,212.71	-	587,777.57	1,035,213.81	1,106,243.00	5,385.00	645,434.00
09/30/2028	-	54,710.00	7,203,922.71	3,181.00	623,261.48	463,481.33	1,139,629.00	12,719.00	666,101.00
09/30/2029	-	49,119.00	7,253,041.71	-	267,600.33	245,000.00	1,184,426.00	194,672.00	516,226.00
09/30/2030	-	44,228.00	7,297,269.71	-	44,228.00	245,000.00	1,214,389.00	-	546,189.00
09/30/2031	-	39,875.00	7,337,144.71	-	39,875.00	245,000.00	1,244,352.00	-	576,152.00
09/30/2032	-	36,033.00	7,373,177.71	-	36,033.00	245,000.00	1,289,149.00	-	620,949.00

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2008 COST EVALUATION PERIOD

Table 12A: Generation Investments Placed in Service FY 2008 ($000s)

	Investment Placed in Service						Irrigation Assistance		
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment	Cumulative Amount in Serivce	Amortization	Unamortized Amount
09/30/2033	-	51,481.00	7,424,658.71	-	51,481.00	245,000.00	1,329,573.00	-	661,373.00
09/30/2034	-	51,949.00	7,476,607.71	-	51,949.00	245,000.00	1,369,997.00	-	701,797.00
09/30/2035	-	52,461.00	7,529,068.71	20,000.00	52,461.00	225,000.00	1,399,204.00	-	731,004.00
09/30/2036	-	52,957.00	7,582,025.71	25,000.00	52,957.00	200,000.00	1,427,753.00	-	759,553.00
09/30/2037	-	53,494.00	7,635,519.71	-	53,494.00	200,000.00	1,456,461.00	-	788,261.00
09/30/2038	-	54,070.00	7,689,589.71	25,000.00	54,070.00	175,000.00	1,485,771.00	-	817,571.00
09/30/2039	-	54,684.00	7,744,273.71	25,000.00	54,684.00	150,000.00	1,515,082.00	-	846,882.00
09/30/2040	-	55,280.00	7,799,553.71	50,000.00	55,280.00	100,000.00	1,548,917.00	-	880,717.00
09/30/2041	-	55,911.00	7,855,464.71	-	55,911.00	100,000.00	1,582,753.00	-	914,553.00
09/30/2042	-	56,577.00	7,912,041.71	60,000.00	56,577.00	40,000.00	1,617,447.00	-	949,247.00
09/30/2043	-	53,302.00	7,965,343.71	40,000.00	53,302.00	0.00	1,652,142.00	-	983,942.00
09/30/2044	-	50,220.00	8,015,563.71	-	50,220.00	0.00	1,685,083.00	-	1,016,883.00
09/30/2045	-	47,374.00	8,062,937.71	-	47,374.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2046	-	44,703.00	8,107,640.71	-	44,703.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2047	-	42,201.00	8,149,841.71	(0.00)	42,201.00	0.01	1,718,024.00	-	1,049,824.00
09/30/2048	-	39,862.00	8,189,703.71	-	39,862.00	0.01	1,718,024.00	-	1,049,824.00
09/30/2049	-	35,966.00	8,225,669.71	0.00	35,966.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2050	-	32,499.00	8,258,168.71	0.01	32,499.00	(0.01)	1,718,024.00	-	1,049,824.00
09/30/2051	-	29,444.00	8,287,612.71	(0.00)	29,444.00	(0.01)	1,718,024.00	-	1,049,824.00
09/30/2052	-	26,740.00	8,314,352.71	(0.00)	26,740.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2053	-	41,875.00	8,356,227.71	0.00	41,875.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2054	-	42,436.00	8,398,663.71	(0.00)	42,436.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2055	-	43,028.00	8,441,691.71	-	43,028.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2056	-	43,649.00	8,485,340.71	-	43,649.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2057	-	44,255.00	8,529,595.71	-	44,255.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2058	-	44,890.00	8,574,485.71	-	44,890.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2059	-	45,553.00	8,620,038.71	-	45,553.00	0.00	1,718,024.00	-	1,049,824.00
Total	**$5,313,654.71**	**$3,306,384.00**	**-**	**$1,386,721.00**	**$7,233,317.71**	**-**	**-**	**$668,200.00**	**-**

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2024 COST EVALUATION PERIOD

Table 12B: Federal Principal Payments FY 2008 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation	
Date	Generation and Conserv. Bonds (1)	Appropriations	Appropriations	Irrigation Amortization
09/30/2005	116,990.00	154,307.00	-	-
09/30/2006	125,062.00	136,407.00	7.00	-
09/30/2007	68,357.00	101,686.53	229.00	-
09/30/2008	104,300.00	77,094.48	867.00	2,950.00
09/30/2009	59,220.00	32,537.02	-	6,590.00
09/30/2010	30,068.00	110,972.02	-	-
09/30/2011	66,500.00	67,034.26	-	-
09/30/2012	32,000.00	13,994.55	-	706.00
09/30/2013	145,300.00	3,306.43	-	44,178.00
09/30/2014	71,150.00	132,054.23	-	42,744.00
09/30/2015	-	126,822.48	44,201.00	94,541.12
09/30/2016	-	-	-	61,860.78
09/30/2017	-	-	-	3.10
09/30/2018	-	77,680.00	34,813.71	22,943.00
09/30/2019	-	221,365.04	115,576.29	57,816.00
09/30/2020	10,000.00	266,780.77	101,875.00	32,731.00
09/30/2021	36,000.00	231,387.56	148,459.00	14,920.00
09/30/2022	36,000.00	328,889.63	74,233.60	13,318.00
09/30/2023	185,261.00	266,517.69	6,700.40	9,613.00
09/30/2024	36,000.00	443,696.79	-	21,148.00
09/30/2025	-	530,987.25	-	11,234.00
09/30/2026	53,338.38	500,192.22	-	18,128.00
09/30/2027	395,030.62	192,746.95	-	5,385.00
09/30/2028	89,281.00	456,137.95	81,023.53	12,719.00
09/30/2029	-	267,600.33	-	194,672.00
09/30/2030	-	44,228.00	-	-
09/30/2031	-	39,875.00	-	-
09/30/2032	-	36,033.00	-	-
09/30/2033	-	51,481.00	-	-
09/30/2034	-	51,949.00	-	-
09/30/2035	20,000.00	52,461.00	-	-
09/30/2036	25,000.00	52,957.00	-	-
09/30/2037	-	53,494.00	-	-
09/30/2038	25,000.00	54,070.00	-	-
09/30/2039	25,000.00	54,684.00	-	-
09/30/2040	50,000.00	55,280.00	-	-
09/30/2041	-	55,911.00	-	-
09/30/2042	60,000.00	56,577.00	-	-
09/30/2043	40,000.00	53,302.00	-	-
09/30/2044	-	50,220.00	-	-
09/30/2045	-	47,374.00	-	-
09/30/2046	-	44,703.00	-	-
09/30/2047	-	42,201.00	0.00	-
09/30/2048	-	39,862.00	-	-
09/30/2049	-	35,966.00	-	-
09/30/2050	-	32,499.01	-	-
09/30/2051	-	29,444.00	(0.00)	-

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
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Table 12B: Federal Principal Payments FY 2008 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation	
Date	Generation and Conserv. Bonds (1)	Appropriations	Appropriations	Irrigation Amortization
09/30/2052	-	26,740.00	-	-
09/30/2053	-	41,875.00	-	-
09/30/2054	-	42,436.00	-	-
09/30/2055	-	43,028.00	-	-
09/30/2056	-	43,649.00	-	-
09/30/2057	-	44,255.00	-	-
09/30/2058	-	44,890.00	-	-
09/30/2059	-	45,553.00	-	-
Total	**$1,904,858.00**	**$6,107,195.18**	**$607,985.53**	**$668,200.00**

(1) Net of interest income and AFUDC.
(2) Includes payments for Lower Snake Fish and Wildlife.

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2024 COST EVALUATION PERIOD

Table 12C: Component of Capitalized Contract Principal Payments FY 2008 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2005	47,949.00	3,824.58	7,693.33	59,466.92
2006	213,983.69	7,465.83	8,880.00	230,329.52
2007	282,861.89	7,837.50	9,300.83	300,000.22
2008	311,190.38	7,512.08	9,695.83	328,398.30
2009	371,036.29		10,160.83	381,197.13
2010	352,757.47		10,646.67	363,404.14
2011	384,357.34		11,148.33	395,505.67
2012	486,373.22		11,699.17	498,072.38
2013	358,803.62		12,276.67	371,080.29
2014	333,313.92		12,895.00	346,208.92
2015	358,322.35		8,817.50	367,139.85
2016	579,194.96		8,943.33	588,138.29
2017	663,217.02		9,402.50	672,619.52
2018	485,242.82		9,872.50	495,115.32
2019	33,482.75		10,366.67	43,849.42
2020	35,776.50		10,885.83	46,662.33
2021	38,227.50		11,435.00	49,662.50
2022	40,845.75		12,014.17	52,859.92
2023	43,644.00		13,028.33	56,672.33
2024	46,634.00		13,682.50	60,316.50
2025	49,828.00		352.50	50,180.50
2026	53,241.50			53,241.50
2027	56,888.75			56,888.75
2028	60,785.25			60,785.25
2029	64,948.75			64,948.75
2030	69,398.25			69,398.25
2031	74,151.50			74,151.50
2032	79,231.00			79,231.00
2033	84,658.50			84,658.50
2034	90,458.00			90,458.00
2035	96,654.25			96,654.25
2036	103,274.75			103,274.75
2037	110,349.00			110,349.00
2038	117,908.00			117,908.00
2039	125,984.25			125,984.25
2040	134,614.50			134,614.50
2041	143,835.75			143,835.75
2042	153,688.50			153,688.50
2043	164,216.00			164,216.00
2044	175,465.25			175,465.25
2045	187,484.50			187,484.50
2046	200,326.75			200,326.75
2047	214,049.00			214,049.00
2048	228,711.75			228,711.75
2049	244,378.50			244,378.50
2050	261,118.25			261,118.25
2051	279,004.50			279,004.50
2052	298,116.50			298,116.50
2053	318,538.00			318,538.00
2054	250,970.25			250,970.25

BONNEVILLE POWER ADMINISTRATION
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Table 12D: Interest Payments FY 2008 ($000s)

Date	BPA Generation and Conserv. Bonds (1)	Corps of Engineers (2) Generation Appropriations	Bureau of Reclamation Generation Appropriations
09/30/2005	30,873.02	170,668.62	42,442.41
09/30/2006	36,288.19	166,706.22	42,442.41
09/30/2007	51,041.50	158,179.22	42,441.92
09/30/2008	67,524.33	155,231.75	42,426.00
09/30/2009	79,641.07	157,925.31	42,363.49
09/30/2010	82,185.62	155,953.53	42,363.49
09/30/2011	80,816.06	156,718.91	42,363.49
09/30/2012	79,605.96	160,090.70	42,363.49
09/30/2013	74,391.83	166,720.34	42,363.49
09/30/2014	64,623.28	173,609.86	42,363.49
09/30/2015	59,997.59	171,307.03	42,363.49
09/30/2016	64,820.67	169,416.86	39,198.71
09/30/2017	66,083.23	176,623.57	39,198.71
09/30/2018	62,787.07	183,861.75	39,198.71
09/30/2019	56,813.61	185,581.43	36,709.52
09/30/2020	56,817.04	177,067.18	28,445.81
09/30/2021	56,280.49	165,348.82	21,161.75
09/30/2022	54,190.07	156,207.72	10,546.92
09/30/2023	59,319.99	140,144.94	5,239.21
09/30/2024	38,718.47	128,281.66	4,760.13
09/30/2025	35,945.00	103,448.78	4,760.13
09/30/2026	38,175.23	71,932.51	4,760.13
09/30/2027	46,377.88	41,991.42	4,760.13
09/30/2028	8,189.95	33,930.51	4,760.13
09/30/2029	177.54	11,203.88	-
09/30/2030	184.31	-	-
09/30/2031	191.52	-	-
09/30/2032	199.24	-	-
09/30/2033	207.49	-	-
09/30/2034	216.31	-	-
09/30/2035	225.72	-	-
09/30/2036	(986.52)	-	-
09/30/2037	(2,748.99)	-	-
09/30/2038	(2,737.51)	-	-
09/30/2039	(4,442.82)	-	-
09/30/2040	(6,147.28)	-	-
09/30/2041	(9,416.64)	-	-
09/30/2042	(9,401.67)	-	-
09/30/2043	(13,445.12)	-	-
09/30/2044	(16,050.68)	-	-
09/30/2045	(16,032.42)	-	-
09/30/2046	(16,012.92)	-	-
09/30/2047	(15,992.08)	-	-
09/30/2048	(15,969.79)	-	-
09/30/2049	(15,945.99)	-	-
09/30/2050	(15,920.57)	-	-
09/30/2051	(15,893.40)	-	-
09/30/2052	(15,864.37)	-	-
09/30/2053	(15,833.33)	-	-
09/30/2054	(17,914.20)	-	-
09/30/2055	(24,230.11)	-	-
09/30/2056	(24,230.11)	-	-
09/30/2057	(24,230.11)	-	-
09/30/2058	(24,230.11)	-	-
09/30/2059	(24,230.11)	-	-
Total	**$1,005,002.43**	**$3,538,152.52**	**$709,797.16**

(1) Net of interest income and AFUDC.
(2) Includes payments for Lower Snake Fish and Wildlife.

BONNEVILLE POWER ADMINISTRATION
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Table 12E: Component of Capitalized Contract Interest Payments FY 2008 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2005	256,410.09	562.54	8,073.46	265,046.09
2006	277,220.85	1,140.77	7,672.19	286,033.81
2007	284,069.90	767.48	7,268.30	292,105.68
2008	266,892.86	375.60	8,494.94	275,763.40
2009	256,405.61		8,520.64	264,926.25
2010	231,262.80		8,060.21	239,323.01
2011	207,789.58		7,534.04	215,323.62
2012	190,428.86		6,976.67	197,405.53
2013	170,502.33		6,378.35	176,880.68
2014	145,704.80		5,750.07	151,454.87
2015	112,726.71		5,208.62	117,935.33
2016	96,106.17		4,762.53	100,868.70
2017	65,460.31		4,301.01	69,761.33
2018	104,064.96		3,816.12	107,881.07
2019	303,249.94		3,306.96	306,556.90
2020	301,103.69		2,772.31	303,876.01
2021	298,810.42		2,210.78	301,021.20
2022	296,360.04		1,620.86	297,980.89
2023	293,741.82		990.91	294,732.73
2024	290,944.24		340.77	291,285.01
2025	287,955.00		9.17	287,964.17
2026	284,761.03			284,761.03
2027	281,348.25			281,348.25
2028	277,701.68			277,701.68
2029	273,805.35			273,805.35
2030	269,642.13			269,642.13
2031	265,193.70			265,193.70
2032	260,440.59			260,440.59
2033	255,361.88			255,361.88
2034	249,935.28			249,935.28
2035	244,136.92			244,136.92
2036	237,941.38			237,941.38
2037	231,321.47			231,321.47
2038	224,248.10			224,248.10
2039	216,690.19			216,690.19
2040	208,614.60			208,614.60
2041	199,985.81			199,985.81
2042	190,765.94			190,765.94
2043	180,914.51			180,914.51
2044	170,388.26			170,388.26
2045	159,140.94			159,140.94
2046	147,123.19			147,123.19
2047	134,282.24			134,282.24
2048	120,561.70			120,561.70
2049	105,901.28			105,901.28
2050	90,236.62			90,236.62
2051	73,498.94			73,498.94
2052	55,614.75			55,614.75
2053	36,505.48			36,505.48
2054	16,087.19			16,087.19

Table 12D: Summary of Payments FY 2008 ($000s)

	Principal			Interest		
Date	Generation Payment	Capitalized Contracts Payment	Total Principal Payment	Generation Payment	Capitalized Contracts Payment	Total Interest Payment
09/30/2005	271,297.00	59,466.92	330,763.92	243,984.05	265,046.09	509,030.14
09/30/2006	261,476.00	230,329.52	491,805.52	245,436.82	286,033.81	531,470.63
09/30/2007	170,272.53	300,000.22	470,272.75	251,662.64	292,105.68	543,768.32
09/30/2008	185,211.48	328,398.30	513,609.78	265,182.08	275,763.40	540,945.48
09/30/2009	98,347.02	381,197.13	479,544.15	279,929.87	264,926.25	544,856.12
09/30/2010	141,040.02	363,404.14	504,444.16	280,502.64	239,323.01	519,825.65
09/30/2011	133,534.26	395,505.67	529,039.93	279,898.46	215,323.62	495,222.08
09/30/2012	46,700.55	498,072.38	544,772.93	282,060.15	197,405.53	479,465.68
09/30/2013	192,784.43	371,080.29	563,864.72	283,475.66	176,880.68	460,356.34
09/30/2014	245,948.23	346,208.92	592,157.15	280,596.63	151,454.87	432,051.50
09/30/2015	265,564.60	367,139.85	632,704.45	273,668.11	117,935.33	391,603.44
09/30/2016	61,860.78	588,138.29	649,999.07	273,436.24	100,868.70	374,304.94
09/30/2017	3.10	672,619.52	672,622.62	281,905.51	69,761.33	351,666.84
09/30/2018	135,436.71	495,115.32	630,552.03	285,847.53	107,881.07	393,728.60
09/30/2019	394,757.33	43,849.42	438,606.75	279,104.56	306,556.90	585,661.46
09/30/2020	411,386.77	46,662.33	458,049.10	262,330.03	303,876.01	566,206.04
09/30/2021	430,766.56	49,662.50	480,429.06	242,791.06	301,021.20	543,812.26
09/30/2022	452,441.23	52,859.92	505,301.15	220,944.71	297,980.89	518,925.60
09/30/2023	468,092.09	56,672.33	524,764.42	204,704.14	294,732.73	499,436.87
09/30/2024	500,844.79	60,316.50	561,161.29	171,760.26	291,285.01	463,045.27
09/30/2025	542,221.25	50,180.50	592,401.75	144,153.91	287,964.17	432,118.08
09/30/2026	571,658.60	53,241.50	624,900.10	114,867.87	284,761.03	399,628.90
09/30/2027	593,162.57	56,888.75	650,051.32	93,129.43	281,348.25	374,477.68
09/30/2028	639,161.48	60,785.25	699,946.73	46,880.59	277,701.68	324,582.27
09/30/2029	462,272.33	64,948.75	527,221.08	11,381.42	273,805.35	285,186.77
09/30/2030	44,228.00	69,398.25	113,626.25	184.31	269,642.13	269,826.44
09/30/2031	39,875.00	74,151.50	114,026.50	191.52	265,193.70	265,385.22
09/30/2032	36,033.00	79,231.00	115,264.00	199.24	260,440.59	260,639.83
09/30/2033	51,481.00	84,658.50	136,139.50	207.49	255,361.88	255,569.37
09/30/2034	51,949.00	90,458.00	142,407.00	216.31	249,935.28	250,151.59
09/30/2035	72,461.00	96,654.25	169,115.25	225.72	244,136.92	244,362.64

BONNEVILLE POWER ADMINISTRATION
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Table 12D: Summary of Payments FY 2008 ($000s)

	Principal			Interest		
Date	Generation Payment	Capitalized Contracts Payment	Total Principal Payment	Generation Payment	Capitalized Contracts Payment	Total Interest Payment
09/30/2036	77,957.00	103,274.75	181,231.75	(986.52)	237,941.38	236,954.86
09/30/2037	53,494.00	110,349.00	163,843.00	(2,748.99)	231,321.47	228,572.48
09/30/2038	79,070.00	117,908.00	196,978.00	(2,737.51)	224,248.10	221,510.59
09/30/2039	79,684.00	125,984.25	205,668.25	(4,442.82)	216,690.19	212,247.37
09/30/2040	105,280.00	134,614.50	239,894.50	(6,147.28)	208,614.60	202,467.32
09/30/2041	55,911.00	143,835.75	199,746.75	(9,416.64)	199,985.81	190,569.17
09/30/2042	116,577.00	153,688.50	270,265.50	(9,401.67)	190,765.94	181,364.27
09/30/2043	93,302.00	164,216.00	257,518.00	(13,445.12)	180,914.51	167,469.39
09/30/2044	50,220.00	175,465.25	225,685.25	(16,050.68)	170,388.26	154,337.58
09/30/2045	47,374.00	187,484.50	234,858.50	(16,032.42)	159,140.94	143,108.52
09/30/2046	44,703.00	200,326.75	245,029.75	(16,012.92)	147,123.19	131,110.27
09/30/2047	42,201.00	214,049.00	256,250.00	(15,992.08)	134,282.24	118,290.16
09/30/2048	39,862.00	228,711.75	268,573.75	(15,969.79)	120,561.70	104,591.91
09/30/2049	35,966.00	244,378.50	280,344.50	(15,945.99)	105,901.28	89,955.29
09/30/2050	32,499.01	261,118.25	293,617.26	(15,920.57)	90,236.62	74,316.04
09/30/2051	29,444.00	279,004.50	308,448.50	(15,893.40)	73,498.94	57,605.54
09/30/2052	26,740.00	298,116.50	324,856.50	(15,864.37)	55,614.75	39,750.38
09/30/2053	41,875.00	318,538.00	360,413.00	(15,833.33)	36,505.48	20,672.15
09/30/2054	42,436.00	250,970.25	293,406.25	(17,914.20)	16,087.19	(1,827.01)
09/30/2055	43,028.00	-	43,028.00	(24,230.11)	-	(24,230.11)
09/30/2056	43,649.00	-	43,649.00	(24,230.11)	-	(24,230.11)
09/30/2057	44,255.00	-	44,255.00	(24,230.11)	-	(24,230.11)
09/30/2058	44,890.00	-	44,890.00	(24,230.11)	-	(24,230.11)
09/30/2059	45,553.00	-	45,553.00	(24,230.11)	-	(24,230.11)
Total	**$9,016,941.71**	**$10,139,862.81**	**$19,156,804.52**	**$5,008,968.06**	**$10,041,229.58**	**$15,050,197.64**

BONNEVILLE POWER ADMINISTRATION
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Table 12G: Summary of Federal Outstanding Balance FY 2008 ($000s)

Date	Unamortized Investment	Term Schedule
09/30/2004	3,924,866.71	5,407,769.71
09/30/2005	3,965,583.71	5,454,196.71
09/30/2006	3,950,635.71	5,462,462.71
09/30/2007	4,069,607.18	5,291,205.71
09/30/2008	4,250,516.70	5,287,800.71
09/30/2009	4,382,337.68	5,374,043.71
09/30/2010	4,367,477.66	5,425,319.71
09/30/2011	4,351,875.40	5,421,634.71
09/30/2012	4,416,005.85	5,421,528.71
09/30/2013	4,370,231.42	5,239,060.71
09/30/2014	4,270,234.19	5,246,243.71
09/30/2015	4,202,811.71	5,229,844.71
09/30/2016	4,306,804.71	5,331,133.71
09/30/2017	4,411,251.71	5,369,454.71
09/30/2018	4,403,719.00	5,429,210.71
09/30/2019	4,172,309.67	5,409,970.71
09/30/2020	3,899,807.90	5,397,295.71
09/30/2021	3,590,788.34	5,384,274.71
09/30/2022	3,259,210.11	5,388,090.71
09/30/2023	2,896,462.02	5,274,808.71
09/30/2024	2,502,123.23	5,316,898.71
09/30/2025	2,047,342.98	5,153,615.71
09/30/2026	1,561,954.38	4,985,566.71
09/30/2027	1,035,213.81	4,935,492.71
09/30/2028	463,481.33	4,774,002.71
09/30/2029	245,000.00	4,565,700.71
09/30/2030	245,000.00	4,606,814.71
09/30/2031	245,000.00	4,604,337.71
09/30/2032	245,000.00	4,433,857.71
09/30/2033	245,000.00	4,186,009.71
09/30/2034	245,000.00	4,237,958.71
09/30/2035	225,000.00	4,222,205.71
09/30/2036	200,000.00	4,274,898.71
09/30/2037	200,000.00	4,255,856.71
09/30/2038	175,000.00	4,291,078.71
09/30/2039	150,000.00	4,345,762.71
09/30/2040	100,000.00	4,378,285.71
09/30/2041	100,000.00	4,412,076.71
09/30/2042	40,000.00	4,455,654.71
09/30/2043	0.00	4,337,603.71
09/30/2044	0.00	4,308,775.71
09/30/2045	0.00	4,267,198.71
09/30/2046	0.00	4,283,052.71
09/30/2047	0.00	4,255,182.76
09/30/2048	0.00	4,295,044.76
09/30/2049	0.00	4,287,010.44
09/30/2050	0.01	4,146,802.94
09/30/2051	0.01	3,936,286.55
09/30/2052	0.00	3,816,141.16
09/30/2053	0.00	3,636,480.03
09/30/2054	-	3,413,347.00
09/30/2055	-	3,196,001.00
09/30/2056	-	3,099,559.00
09/30/2057	-	2,957,570.00
09/30/2058	-	2,763,832.00
09/30/2059	0	2,706,178.00
Total	**91,732,653.19**	**257,387,493.22**

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13A: Generation Investments Placed in Service FY 2009 ($000s)

	Investment Placed in Service						Irrigation Assistance		
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment	Cumulative Amount in Serivce	Amortization	Unamortized Amount
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
09/30/2004	3,879,119.71	45,747.00	3,924,866.71	-	-	3,924,866.71	668,200.00	-	668,200.00
09/30/2005	312,014.00	-	4,236,880.71	220,163.00	51,134.00	3,965,583.71	668,200.00	-	668,200.00
09/30/2006	246,528.00	-	4,483,408.71	178,262.00	83,214.00	3,950,635.71	668,200.00	-	668,200.00
09/30/2007	289,244.00	-	4,772,652.71	77,577.00	92,695.53	4,069,607.18	668,200.00	-	668,200.00
09/30/2008	363,171.00	-	5,135,823.71	104,300.00	77,961.48	4,250,516.70	668,200.00	2,950.00	665,250.00
09/30/2009	223,578.00	-	5,359,401.71	59,220.00	110,637.00	4,304,237.70	668,200.00	6,590.00	658,660.00
09/30/2010	-	126,180.00	5,485,581.71	30,068.00	124,429.14	4,275,920.56	675,142.00	-	665,602.00
09/30/2011	-	117,932.00	5,603,513.71	66,500.00	81,432.74	4,245,919.82	681,708.00	-	672,168.00
09/30/2012	-	110,125.00	5,713,638.71	32,000.00	27,612.19	4,296,432.63	685,184.00	706.00	674,938.00
09/30/2013	-	102,832.00	5,816,470.71	145,300.00	12,262.71	4,241,701.92	704,977.00	44,178.00	650,553.00
09/30/2014	-	103,207.00	5,919,677.71	71,150.00	141,118.89	4,132,640.03	742,507.00	42,744.00	645,339.00
09/30/2015	-	103,601.00	6,023,278.71	-	190,311.12	4,045,929.91	747,614.00	85,285.74	565,160.26
09/30/2016	-	103,993.00	6,127,271.71	-	0.01	4,149,922.90	753,008.00	71,117.53	499,436.73
09/30/2017	-	104,447.00	6,231,718.71	-	-	4,254,369.90	788,261.00	1.73	534,688.00
09/30/2018	-	104,961.00	6,336,679.71	-	113,699.11	4,245,631.79	839,448.00	22,943.00	562,932.00
09/30/2019	-	105,532.00	6,442,211.71	-	360,569.34	3,990,594.45	850,350.00	57,816.00	516,018.00
09/30/2020	-	106,154.00	6,548,365.71	10,000.00	393,973.15	3,692,775.30	871,608.00	32,731.00	504,545.00
09/30/2021	-	106,827.00	6,655,192.71	36,000.00	406,974.15	3,356,628.15	910,815.00	14,920.00	528,832.00
09/30/2022	-	107,545.00	6,762,737.71	36,000.00	424,600.14	3,003,573.01	949,864.00	13,318.00	554,563.00
09/30/2023	-	95,731.00	6,858,468.71	36,000.00	460,467.51	2,602,836.50	978,944.00	9,613.00	574,030.00
09/30/2024	-	85,358.00	6,943,826.71	36,000.00	476,369.80	2,175,824.70	1,020,750.00	21,148.00	594,688.00
09/30/2025	-	76,207.00	7,020,033.71	-	565,924.50	1,686,107.20	1,040,787.00	11,234.00	603,491.00
09/30/2026	-	68,142.00	7,088,175.71	-	576,569.13	1,177,680.07	1,074,015.00	18,128.00	618,591.00
09/30/2027	-	61,037.00	7,149,212.71	-	637,032.90	601,684.17	1,106,243.00	5,385.00	645,434.00
09/30/2028	-	54,710.00	7,203,922.71	3,181.00	408,213.17	245,000.00	1,139,629.00	207,391.00	471,429.00
09/30/2029	-	49,119.00	7,253,041.71	-	49,119.00	245,000.00	1,184,426.00	-	516,226.00
09/30/2030	-	44,228.00	7,297,269.71	-	44,228.00	245,000.00	1,214,389.00	-	546,189.00
09/30/2031	-	39,875.00	7,337,144.71	-	39,875.00	245,000.00	1,244,352.00	-	576,152.00
09/30/2032	-	36,033.00	7,373,177.71	-	36,033.00	245,000.00	1,289,149.00	-	620,949.00

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13A: Generation Investments Placed in Service FY 2009 ($000s)

	Investment Placed in Service						Irrigation Assistance		
Date	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	UnAmortized Investment	Cumulative Amount in Serivce	Amortization	Unamortized Amount
09/30/2033	-	51,481.00	7,424,658.71	-	51,481.00	245,000.00	1,329,573.00	-	661,373.00
09/30/2034	-	51,949.00	7,476,607.71	-	51,949.00	245,000.00	1,369,997.00	-	701,797.00
09/30/2035	-	52,461.00	7,529,068.71	20,000.00	52,461.00	225,000.00	1,399,204.00	-	731,004.00
09/30/2036	-	52,957.00	7,582,025.71	25,000.00	52,957.00	200,000.00	1,427,753.00	-	759,553.00
09/30/2037	-	53,494.00	7,635,519.71	-	53,494.00	200,000.00	1,456,461.00	-	788,261.00
09/30/2038	-	54,070.00	7,689,589.71	25,000.00	54,070.00	175,000.00	1,485,771.00	-	817,571.00
09/30/2039	-	54,684.00	7,744,273.71	25,000.00	54,684.00	150,000.00	1,515,082.00	-	846,882.00
09/30/2040	-	55,280.00	7,799,553.71	50,000.00	55,280.00	100,000.00	1,548,917.00	-	880,717.00
09/30/2041	-	55,911.00	7,855,464.71	-	55,911.00	100,000.00	1,582,753.00	-	914,553.00
09/30/2042	-	56,577.00	7,912,041.71	60,000.00	56,577.00	40,000.00	1,617,447.00	-	949,247.00
09/30/2043	-	53,302.00	7,965,343.71	40,000.00	53,302.00	0.00	1,652,142.00	-	983,942.00
09/30/2044	-	50,220.00	8,015,563.71	-	50,220.00	0.00	1,685,083.00	-	1,016,883.00
09/30/2045	-	47,374.00	8,062,937.71	-	47,374.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2046	-	44,703.00	8,107,640.71	-	44,703.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2047	-	42,201.00	8,149,841.71	(0.00)	42,201.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2048	-	39,862.00	8,189,703.71	-	39,862.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2049	-	35,966.00	8,225,669.71	0.00	35,966.00	0.00	1,718,024.00	-	1,049,824.00
09/30/2050	-	32,499.00	8,258,168.71	0.01	32,499.00	(0.01)	1,718,024.00	-	1,049,824.00
09/30/2051	-	29,444.00	8,287,612.71	(0.00)	29,444.00	(0.01)	1,718,024.00	-	1,049,824.00
09/30/2052	-	26,740.00	8,314,352.71	(0.00)	26,740.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2053	-	41,875.00	8,356,227.71	0.00	41,875.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2054	-	42,436.00	8,398,663.71	(0.00)	42,436.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2055	-	43,028.00	8,441,691.71	-	43,028.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2056	-	43,649.00	8,485,340.71	-	43,649.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2057	-	44,255.00	8,529,595.71	-	44,255.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2058	-	44,890.00	8,574,485.71	-	44,890.00	(0.00)	1,718,024.00	-	1,049,824.00
09/30/2059	-	45,553.00	8,620,038.71	-	45,553.00	(0.00)	1,718,024.00	-	1,049,824.00
Total	**$5,313,654.71**	**$3,306,384.00**	**-**	**$1,386,721.00**	**$7,233,317.71**	**-**	**-**	**$668,200.00**	**-**

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13B: Federal Principal Payments FY 2009 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation	
Date	Bonds (1)	Appropriations	Appropriations	Irrigation Amortization
09/30/2005	116,990.00	154,307.00	-	-
09/30/2006	125,062.00	136,407.00	7.00	-
09/30/2007	68,357.00	101,686.53	229.00	-
09/30/2008	104,300.00	77,094.48	867.00	2,950.00
09/30/2009	59,220.00	110,637.00	-	6,590.00
09/30/2010	30,068.00	124,429.14	-	-
09/30/2011	66,500.00	81,432.74	-	-
09/30/2012	32,000.00	27,612.19	-	706.00
09/30/2013	145,300.00	12,262.71	-	44,178.00
09/30/2014	71,150.00	96,917.89	44,201.00	42,744.00
09/30/2015	-	124,902.32	65,408.80	85,285.74
09/30/2016	-	-	0.01	71,117.53
09/30/2017	-	-	-	1.73
09/30/2018	-	79,012.92	34,686.19	22,943.00
09/30/2019	-	210,490.34	150,079.00	57,816.00
09/30/2020	10,000.00	334,394.15	59,579.00	32,731.00
09/30/2021	36,000.00	314,067.59	92,906.56	14,920.00
09/30/2022	185,261.00	196,340.70	78,998.44	13,318.00
09/30/2023	36,000.00	460,467.51	-	9,613.00
09/30/2024	36,000.00	476,369.80	-	21,148.00
09/30/2025	-	565,924.50	-	11,234.00
09/30/2026	431,795.69	144,773.44	-	18,128.00
09/30/2027	102,673.31	453,336.06	81,023.53	5,385.00
09/30/2028	3,181.00	408,213.17	-	207,391.00
09/30/2029	-	49,119.00	-	-
09/30/2030	-	44,228.00	-	-
09/30/2031	-	39,875.00	-	-
09/30/2032	-	36,033.00	-	-
09/30/2033	-	51,481.00	-	-
09/30/2034	-	51,949.00	-	-
09/30/2035	20,000.00	52,461.00	-	-
09/30/2036	25,000.00	52,957.00	-	-
09/30/2037	-	53,494.00	-	-
09/30/2038	25,000.00	54,070.00	-	-
09/30/2039	25,000.00	54,684.00	-	-
09/30/2040	50,000.00	55,280.00	-	-
09/30/2041	-	55,911.00	-	-
09/30/2042	60,000.00	56,577.00	-	-
09/30/2043	40,000.00	53,302.00	-	-
09/30/2044	-	50,220.00	-	-
09/30/2045	-	47,374.00	-	-
09/30/2046	-	44,703.00	-	-
09/30/2047	-	42,201.00	-	-
09/30/2048	-	39,862.00	-	-
09/30/2049	-	35,966.00	-	-
09/30/2050	-	32,499.01	-	-
09/30/2051	-	29,444.00	(0.00)	-

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13B: Federal Principal Payments FY 2009 ($000s)

	BPA	Corps of Engineers (2)	Bureau of Reclamation	
Date	Bonds (1)	Appropriations	Appropriations	Irrigation Amortization
09/30/2052	-	26,740.00	-	-
09/30/2053	-	41,875.00	-	-
09/30/2054	-	42,436.00	-	-
09/30/2055	-	43,028.00	-	-
09/30/2056	-	43,649.00	-	-
09/30/2057	-	44,255.00	-	-
09/30/2058	-	44,890.00	-	-
09/30/2059	-	45,553.00	-	-
	$1,904,858.00	**$6,107,195.18**	**$607,985.53**	**$668,200.00**

(1) Net of interest income and AFUDC.
(2) Includes payments for Lower Snake Fish and Wildlife.

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13C: Component of Capitalized Contract Principal Payments FY 2009 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2005	47,949.00	3,824.58	7,693.33	59,466.92
2006	213,983.69	7,465.83	8,880.00	230,329.52
2007	282,861.89	7,837.50	9,300.83	300,000.22
2008	291,652.05	7,512.08	9,695.83	308,859.96
2009	312,421.28		10,160.83	322,582.11
2010	352,572.47		10,646.67	363,219.14
2011	383,954.84		11,148.33	395,103.17
2012	487,689.41		11,699.17	499,388.58
2013	365,668.92		12,276.67	377,945.58
2014	341,045.55		12,895.00	353,940.55
2015	366,153.84		8,817.50	374,971.34
2016	589,545.64		8,943.33	598,488.98
2017	683,176.33		9,402.50	692,578.83
2018	507,207.82		9,872.50	517,080.32
2019	33,482.75		10,366.67	43,849.42
2020	35,776.50		10,885.83	46,662.33
2021	38,227.50		11,435.00	49,662.50
2022	40,845.75		12,014.17	52,859.92
2023	43,644.00		13,028.33	56,672.33
2024	46,634.00		13,682.50	60,316.50
2025	49,828.00		352.50	50,180.50
2026	53,241.50			53,241.50
2027	56,888.75			56,888.75
2028	60,785.25			60,785.25
2029	64,948.75			64,948.75
2030	69,398.25			69,398.25
2031	74,151.50			74,151.50
2032	79,231.00			79,231.00
2033	84,658.50			84,658.50
2034	90,458.00			90,458.00
2035	96,654.25			96,654.25
2036	103,274.75			103,274.75
2037	110,349.00			110,349.00
2038	117,908.00			117,908.00
2039	125,984.25			125,984.25
2040	134,614.50			134,614.50
2041	143,835.75			143,835.75
2042	153,688.50			153,688.50
2043	164,216.00			164,216.00
2044	175,465.25			175,465.25
2045	187,484.50			187,484.50
2046	200,326.75			200,326.75
2047	214,049.00			214,049.00
2048	228,711.75			228,711.75
2049	244,378.50			244,378.50
2050	261,118.25			261,118.25
2051	279,004.50			279,004.50
2052	298,116.50			298,116.50
2053	318,538.00			318,538.00
2054	250,970.25			250,970.25

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13D: Federal Interest Payments FY 2009 ($000s)

Date	BPA Generation and Conserv. Bonds (1)	Corps of Engineers (2) Generation Appropriations		Bureau of Reclamation Generation Appropriations
09/30/2005	30,872.77	170,668.62		42,442.41
09/30/2006	36,287.94	166,706.22		42,442.41
09/30/2007	51,041.25	158,179.22		42,441.92
09/30/2008	67,513.40	155,231.75		42,426.00
09/30/2009	78,158.18	157,925.31		42,363.49
09/30/2010	82,004.44	150,338.14		42,363.49
09/30/2011	80,634.89	150,162.16		42,363.49
09/30/2012	79,466.61	152,504.27		42,363.49
09/30/2013	74,382.70	158,158.90		42,363.49
09/30/2014	64,626.47	164,407.15		42,363.49
09/30/2015	59,993.24	164,627.51		39,198.71
09/30/2016	64,865.96	162,876.53		34,521.96
09/30/2017	66,342.42	170,083.24		34,521.96
09/30/2018	63,018.37	177,321.42		34,521.96
09/30/2019	56,528.86	178,945.79		32,041.90
09/30/2020	56,532.29	171,209.11		21,311.25
09/30/2021	55,995.74	154,656.38		17,051.35
09/30/2022	61,495.64	139,603.64		10,408.52
09/30/2023	40,785.94	133,209.65		4,760.13
09/30/2024	38,433.72	107,933.40		4,760.13
09/30/2025	35,660.25	80,836.28		4,760.13
09/30/2026	52,210.35	46,898.86		4,760.13
09/30/2027	9,530.18	41,623.79		4,760.13
09/30/2028	100.83	18,461.30		-
09/30/2029	(107.20)	-		-
09/30/2030	(100.43)	-		-
09/30/2031	(93.22)	-		-
09/30/2032	(85.51)	-		-
09/30/2033	(77.26)	-		-
09/30/2034	(68.44)	-		-
09/30/2035	(59.03)	-		-
09/30/2036	(1,271.26)	-		-
09/30/2037	(3,033.74)	-		-
09/30/2038	(3,022.25)	-		-
09/30/2039	(4,727.57)	-		-
09/30/2040	(6,432.02)	-		-
09/30/2041	(9,701.38)	-		-
09/30/2042	(9,686.42)	-		-
09/30/2043	(13,729.87)	-		-
09/30/2044	(16,335.42)	-		-
09/30/2045	(16,317.17)	-		-
09/30/2046	(16,297.67)	-		-
09/30/2047	(16,276.82)	-		-
09/30/2048	(16,254.54)	-		-
09/30/2049	(16,230.74)	-		-
09/30/2050	(16,205.31)	-		-
09/30/2051	(16,178.15)	-		-
09/30/2052	(16,149.11)	-		-
09/30/2053	(16,118.08)	-		-
09/30/2054	(18,198.95)	-		-
09/30/2055	(24,514.86)	-		-
09/30/2056	(24,514.86)	-		-
09/30/2057	(24,514.86)	-		-
09/30/2058	(24,514.86)	-		-
09/30/2059	(24,514.86)	-		-
Total	**$951,150.58**	**$3,332,568.64**	-	**$671,311.94**

(1) Net of interest income and AFUDC.
(2) Includes payments for Lower Snake Fish and Wildlife.

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13E: Component of Capitalized Contract Interest Payments FY 2009 ($000s)

Fiscal Year	Supply System Projects	Trojan	Other	Total
2005	255,954.80	562.54	8,073.46	264,590.80
2006	276,430.90	1,140.77	7,672.19	285,243.86
2007	282,491.18	767.48	7,268.30	290,526.96
2008	265,798.92	375.60	8,494.94	274,669.46
2009	256,362.22		8,520.64	264,882.86
2010	235,827.42		8,060.21	243,887.63
2011	212,384.67		7,534.04	219,918.71
2012	195,047.84		6,976.67	202,024.51
2013	175,050.09		6,378.35	181,428.44
2014	149,879.39		5,750.07	155,629.46
2015	116,800.24		5,208.62	122,008.86
2016	99,402.43		4,762.53	104,164.96
2017	68,165.27		4,301.01	72,466.28
2018	105,624.48		3,816.12	109,440.60
2019	303,249.94		3,306.96	306,556.90
2020	301,103.69		2,772.31	303,876.01
2021	298,810.42		2,210.78	301,021.20
2022	296,360.04		1,620.86	297,980.89
2023	293,741.82		990.91	294,732.73
2024	290,944.24		340.77	291,285.01
2025	287,955.00		9.17	287,964.17
2026	284,761.03			284,761.03
2027	281,348.25			281,348.25
2028	277,701.68			277,701.68
2029	273,805.35			273,805.35
2030	269,642.13			269,642.13
2031	265,193.70			265,193.70
2032	260,440.59			260,440.59
2033	255,361.88			255,361.88
2034	249,935.28			249,935.28
2035	244,136.92			244,136.92
2036	237,941.38			237,941.38
2037	231,321.47			231,321.47
2038	224,248.10			224,248.10
2039	216,690.19			216,690.19
2040	208,614.60			208,614.60
2041	199,985.81			199,985.81
2042	190,765.94			190,765.94
2043	180,914.51			180,914.51
2044	170,388.26			170,388.26
2045	159,140.94			159,140.94
2046	147,123.19			147,123.19
2047	134,282.24			134,282.24
2048	120,561.70			120,561.70
2049	105,901.28			105,901.28
2050	90,236.62			90,236.62
2051	73,498.94			73,498.94
2052	55,614.75			55,614.75
2053	36,505.48			36,505.48
2054	16,087.19			16,087.19

BONNEVILLE POWER ADMINISTRATION
GENERATION REPAYMENT STUDY
OCTOBER 1, 2004 - SEPTEMBER 30, 2009 COST EVALUATION PERIOD

Table 13F: Summary of Payments FY 2009 ($000s)

	Principal			Interest		
Date	Generation Payment	Capitalized Contracts Payment	Total Principal Payment	Generation Payment	Capitalized Contracts Payment	Total Interest Payment
09/30/2005	271,297.00	59,466.92	330,763.92	243,983.80	264,590.80	508,574.60
09/30/2006	261,476.00	230,329.52	491,805.52	245,436.57	285,243.86	530,680.43
09/30/2007	170,272.53	300,000.22	470,272.75	251,662.39	290,526.96	542,189.35
09/30/2008	185,211.48	308,859.96	494,071.44	265,171.15	274,669.46	539,840.61
09/30/2009	176,447.00	322,582.11	499,029.11	278,446.98	264,882.86	543,329.84
09/30/2010	154,497.14	363,219.14	517,716.28	274,706.07	243,887.63	518,593.70
09/30/2011	147,932.74	395,103.17	543,035.91	273,160.54	219,918.71	493,079.25
09/30/2012	60,318.19	499,388.58	559,706.77	274,334.37	202,024.51	476,358.88
09/30/2013	201,740.71	377,945.58	579,686.29	274,905.09	181,428.44	456,333.53
09/30/2014	255,012.89	353,940.55	608,953.44	271,397.11	155,629.46	427,026.57
09/30/2015	275,596.86	374,971.34	650,568.20	263,819.46	122,008.86	385,828.32
09/30/2016	71,117.54	598,488.98	669,606.52	262,264.45	104,164.96	366,429.41
09/30/2017	1.73	692,578.83	692,580.56	270,947.62	72,466.28	343,413.90
09/30/2018	136,642.11	517,080.32	653,722.43	274,861.75	109,440.60	384,302.35
09/30/2019	418,385.34	43,849.42	462,234.76	267,516.55	306,556.90	574,073.45
09/30/2020	436,704.15	46,662.33	483,366.48	249,052.65	303,876.01	552,928.66
09/30/2021	457,894.15	49,662.50	507,556.65	227,703.47	301,021.20	528,724.67
09/30/2022	473,918.14	52,859.92	526,778.06	211,507.80	297,980.89	509,488.69
09/30/2023	506,080.51	56,672.33	562,752.84	178,755.72	294,732.73	473,488.45
09/30/2024	533,517.80	60,316.50	593,834.30	151,127.25	291,285.01	442,412.26
09/30/2025	577,158.50	50,180.50	627,339.00	121,256.66	287,964.17	409,220.83
09/30/2026	594,697.13	53,241.50	647,938.63	103,869.34	284,761.03	388,630.37
09/30/2027	642,417.90	56,888.75	699,306.65	55,914.10	281,348.25	337,262.35
09/30/2028	618,785.17	60,785.25	679,570.42	18,562.13	277,701.68	296,263.81
09/30/2029	49,119.00	64,948.75	114,067.75	(107.20)	273,805.35	273,698.15
09/30/2030	44,228.00	69,398.25	113,626.25	(100.43)	269,642.13	269,541.70
09/30/2031	39,875.00	74,151.50	114,026.50	(93.22)	265,193.70	265,100.48
09/30/2032	36,033.00	79,231.00	115,264.00	(85.51)	260,440.59	260,355.08
09/30/2033	51,481.00	84,658.50	136,139.50	(77.26)	255,361.88	255,284.62
09/30/2034	51,949.00	90,458.00	142,407.00	(68.44)	249,935.28	249,866.84
09/30/2035	72,461.00	96,654.25	169,115.25	(59.03)	244,136.92	244,077.89

BONNEVILLE POWER ADMINISTRATION
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Table 13F: Summary of Payments FY 2009 ($000s)

	Principal			Interest		
Date	Generation Payment	Capitalized Contracts Payment	Total Principal Payment	Generation Payment	Capitalized Contracts Payment	Total Interest Payment
09/30/2036	77,957.00	103,274.75	181,231.75	(1,271.26)	237,941.38	236,670.12
09/30/2037	53,494.00	110,349.00	163,843.00	(3,033.74)	231,321.47	228,287.73
09/30/2038	79,070.00	117,908.00	196,978.00	(3,022.25)	224,248.10	221,225.85
09/30/2039	79,684.00	125,984.25	205,668.25	(4,727.57)	216,690.19	211,962.62
09/30/2040	105,280.00	134,614.50	239,894.50	(6,432.02)	208,614.60	202,182.58
09/30/2041	55,911.00	143,835.75	199,746.75	(9,701.38)	199,985.81	190,284.43
09/30/2042	116,577.00	153,688.50	270,265.50	(9,686.42)	190,765.94	181,079.52
09/30/2043	93,302.00	164,216.00	257,518.00	(13,729.87)	180,914.51	167,184.64
09/30/2044	50,220.00	175,465.25	225,685.25	(16,335.42)	170,388.26	154,052.84
09/30/2045	47,374.00	187,484.50	234,858.50	(16,317.17)	159,140.94	142,823.77
09/30/2046	44,703.00	200,326.75	245,029.75	(16,297.67)	147,123.19	130,825.52
09/30/2047	42,201.00	214,049.00	256,250.00	(16,276.82)	134,282.24	118,005.42
09/30/2048	39,862.00	228,711.75	268,573.75	(16,254.54)	120,561.70	104,307.16
09/30/2049	35,966.00	244,378.50	280,344.50	(16,230.74)	105,901.28	89,670.54
09/30/2050	32,499.01	261,118.25	293,617.26	(16,205.31)	90,236.62	74,031.30
09/30/2051	29,444.00	279,004.50	308,448.50	(16,178.15)	73,498.94	57,320.79
09/30/2052	26,740.00	298,116.50	324,856.50	(16,149.11)	55,614.75	39,465.64
09/30/2053	41,875.00	318,538.00	360,413.00	(16,118.08)	36,505.48	20,387.40
09/30/2054	42,436.00	250,970.25	293,406.25	(18,198.95)	16,087.19	(2,111.76)
09/30/2055	43,028.00	-	43,028.00	(24,514.86)	-	(24,514.86)
09/30/2056	43,649.00	-	43,649.00	(24,514.86)	-	(24,514.86)
09/30/2057	44,255.00	-	44,255.00	(24,514.86)	-	(24,514.86)
09/30/2058	44,890.00	-	44,890.00	(24,514.86)	-	(24,514.86)
09/30/2059	45,553.00	-	45,553.00	(24,514.86)	-	(24,514.86)
Total	**$9,288,238.71**	**$10,196,608.48**	**$19,484,847.19**	**$4,955,031.16**	**$10,336,449.68**	**$15,291,480.84**

BONNEVILLE POWER ADMINISTRATION
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Table 13G: Summary of Federal Outstanding Balance FY 2009 ($000s)

Date	Unamortized Investment	Term Schedule
09/30/2004	3,924,866.71	5,407,769.71
09/30/2005	3,965,583.71	5,454,196.71
09/30/2006	3,950,635.71	5,462,462.71
09/30/2007	4,069,607.18	5,291,205.71
09/30/2008	4,250,516.70	5,287,800.71
09/30/2009	4,304,237.70	5,374,043.71
09/30/2010	4,275,920.56	5,425,319.71
09/30/2011	4,245,919.82	5,421,634.71
09/30/2012	4,296,432.63	5,421,528.71
09/30/2013	4,241,701.92	5,239,060.71
09/30/2014	4,132,640.03	5,246,243.71
09/30/2015	4,045,929.91	5,229,844.71
09/30/2016	4,149,922.90	5,331,133.71
09/30/2017	4,254,369.90	5,369,454.71
09/30/2018	4,245,631.79	5,429,210.71
09/30/2019	3,990,594.45	5,409,970.71
09/30/2020	3,692,775.30	5,397,295.71
09/30/2021	3,356,628.15	5,384,274.71
09/30/2022	3,003,573.01	5,388,090.71
09/30/2023	2,602,836.50	5,274,808.71
09/30/2024	2,175,824.70	5,316,898.71
09/30/2025	1,686,107.20	5,153,615.71
09/30/2026	1,177,680.07	4,985,566.71
09/30/2027	601,684.17	4,935,492.71
09/30/2028	245,000.00	4,774,002.71
09/30/2029	245,000.00	4,565,700.71
09/30/2030	245,000.00	4,606,814.71
09/30/2031	245,000.00	4,604,337.71
09/30/2032	245,000.00	4,433,857.71
09/30/2033	245,000.00	4,186,009.71
09/30/2034	245,000.00	4,237,958.71
09/30/2035	225,000.00	4,222,205.71
09/30/2036	200,000.00	4,274,898.71
09/30/2037	200,000.00	4,255,856.71
09/30/2038	175,000.00	4,291,078.71
09/30/2039	150,000.00	4,345,762.71
09/30/2040	100,000.00	4,378,285.71
09/30/2041	100,000.00	4,412,076.71
09/30/2042	40,000.00	4,455,654.71
09/30/2043	0.00	4,337,603.71
09/30/2044	0.00	4,308,775.71
09/30/2045	0.00	4,267,198.71
09/30/2046	0.00	4,283,052.71
09/30/2047	0.00	4,255,182.76
09/30/2048	0.00	4,295,044.76
09/30/2049	0.00	4,287,010.44
09/30/2050	0.01	4,146,802.94
09/30/2051	0.01	3,936,286.55
09/30/2052	0.00	3,816,141.16
09/30/2053	0.00	3,636,480.03
09/30/2054	-	3,413,347.00
09/30/2055	-	3,196,001.00
09/30/2056	-	3,099,559.00
09/30/2057	-	2,957,570.00
09/30/2058	-	2,763,832.00
Total	**$87,546,620.80**	**$257,387,493.22**