2002 Final Power Rate Proposal
Revenue Requirement Study

WP-02-FS-BPA-02
May 2000

BONNEVILLE
POWER ADMINISTRATION

2002 FINAL PROPOSAL REVENUE REQUIREMENTS 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
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
Alcoa	Alcoa, Inc.
Alcoa/Vanalco	Joint Alcoa and Vanalco
aMW	Average Megawatt
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BASC	BPA Average System Cost
BO	Biological Opinion
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
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAL	Columbia Falls Aluminum Company
Cfs	cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con/Mod	Conservation Modernization Program
COSA	Cost of Service Analysis
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Critical Rule Curves
CRITFC	Columbia River Inter-Tribal Fish Commission
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CTPP	Conditional TPP
CWA	Clear Water Act
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause

DJ	Dow Jones
DMP	Data Management Procedures
DOE	Department of Energy
DROD	Draft Record of Decision
DSI	DSI (only the DSI represented by Murphy under DS)
DSIs	Direct Service Industrial Customers
ECC	Energy Content Curve
EFB	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
Energy Northwest	Formerly Washington Public Power Supply System (Nuclear) Project
Energy Services	Energy Services, Inc.
Enron	Enron Corporation
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	Firm Energy Load Carrying Capability
FERC	Federal Energy Regulatory Commission
Fourth Power Plan	NWPPC's Fourth 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)
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
HNF	Hourly Non-Firm
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.

IPC	Idaho Power Company
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
IJC	International Joint Commission
IOU	IOU (the joint IOU filings)
IOUs	Investor-Owned Utilities
ISC	Investment Service Coverage
ISO	Independent System Operator
JOA	Joint Operating Agency
Joint DSI	Alcoa, Vanalco, and DSI
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LME	London Metal Exchange
LOLP	Loss of Load Probability
L/R Balance	Load/Resource Balance
m/kWh	Mills per kilowatthour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MPC	Montana Power Company
MT	Market Transmission (rate)
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Non-coincidental Demand
NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFRAP	Nonfirm Revenue Analysis Program (model)

NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
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 C&R	Northwest Power Planning Council Cost and Revenues Analysis
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
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
PGE	Portland General Electric
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PMDAM	Power Marketing Decision Analysis Model
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Principles	Fish and Wildlife Funding Principles
Project Act	Bonneville Project Act
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People’s Utility District

PURPA	Public Utilities Regulatory Policies Act
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Organization
SCCT	Single-Cycle Combustion Turbine
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
SPG	Slice Purchasers Group
SS	Share-the-Savings Energy (rate)
STREAM	Short-Term Risk Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TACUL	Targeted Adjustment Charge for Uncommitted Loads
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
USFWS	U.S. Fish and Wildlife Service
Vanalco	Vanalco, Inc.
VB	Visual Basic
VBA	Visual Basic for Applications
VI	Variable Industrial Power rate
VOR	Value of Reserves
WAPA	Western Area Power Administration

WEFA	WEFA Group (Wharton Econometric Forecasting Associates)
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordinating Council
WSPP	Western System 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 requirements herein include: recovery of the Federal investment in hydro generation, fish and wildlife recovery, and conservation; Federal agencies' operations and maintenance (O&M) expenses allocated to power; capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest (formerly known as Washington Public Power Supply System); other purchase power 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) 1999-2006. The Study is based on generation revenue requirements for the rate test period FY 2002–2006, 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-02-FS-BPA-02. Volumes 1 and 2 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A and WP-02-FS-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 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 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.

Normally, 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. However, BPA’s Subscription Strategy is driving a substantial restructuring of generation products and services, and the Fish and Wildlife Funding Principles (Principles) require BPA to achieve a specific Treasury Payment Probability (TPP). The need to incorporate these significant policies in the development of wholesale power rates makes the results of this current test immaterial.

Consistent with RA 6120.2 and the standards applied by FERC on review of BPA's rates, the adequacy of proposed rates must be demonstrated. 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 the Revenue Requirement Study, WP-02-FS-BPA-02, 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--an 88 percent probability that United States (U.S.) Treasury payments in the generation function will be recovered on time and in full through wholesale power rates over the five-year rate period. *See* chapter 2.2 of the Revenue Requirement Study, WP-02-FS-BPA-02; and DeWolf *et al.*, WP-02-E-BPA-13.

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed rates over the five-year rate period. In combination with other risk mitigation tools, these net revenues are set at the lowest level necessary to achieve BPA's cost recovery objectives 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 PROPOSED RATES

($000s)

Fiscal Year		Generation
2002	Projected Revenues From Proposed Rates	2,482,418
	Projected Expenses	2,363,505
	Net Revenues	**118,913**
2003	Projected Revenues From Proposed Rates	2,498,185
	Projected Expenses	2,403,486
	Net Revenues	**94,699**
2004	Projected Revenues From Proposed Rates	2,452,144
	Projected Expenses	2,360,214
	Net Revenues	**91,930**
2005	Projected Revenues From Proposed Rates	2,476,673
	Projected Expenses	2,355,464
	Net Revenues	**121,209**
2006	Projected Revenues From Proposed Rates	2,491,853
	Projected Expenses	2,383,690
	Net Revenues	**108,163**
Average FYs 2002-2006	Projected Revenues From Proposed Rates	2,480,255
	Projected Expenses	2,373,272
	Net Revenues */	**106,983**

Source: Table 8A, this Study

The expected value of risk-adjusted reserves at the beginning of the rate period is $842.3 million, and at the end of the rate period is $1,268 million.

*/ Of the $106.98 million average net revenues, approximately $98 million is risk mitigation and $4.0 million is for amortization payments.

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
FYs 2002 – 2006 GENERATION REPAYMENT STUDIES

($000s)

Fiscal Year	Annual Amortization
2002	$107,401
2003	$72,984
2004 *	$92,285
2005	$148,097
2006	$128,476
Total	$549,243

Note: The total amortization is a $239.7million increase over the five-year amount scheduled for generation in BPA's 1996 rate filing, and 3.2 million over the 2002 Final Proposal. This increase is due primarily to the structure of non-Federal debt and increasing repayment obligations for fish and wildlife recovery.

* Includes Irrigation Assistance payment of $739 ($000).

Figure 1 on the next page depicts the revenue requirement development process.

Figure 2 is a pie chart showing the components of the generation revenue requirements.

FIGURE 1

GENERATION REVENUE REQUIREMENT PROCESS

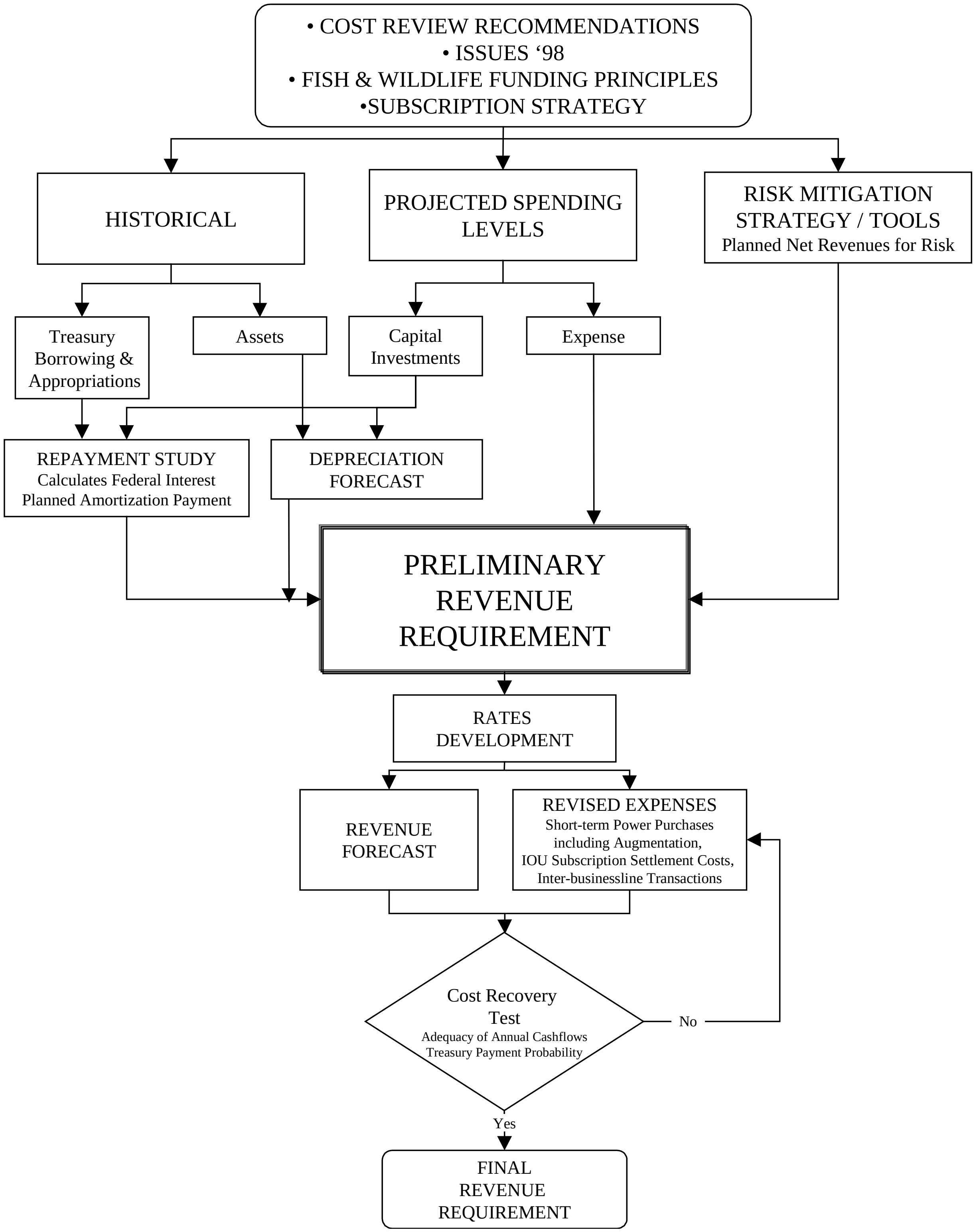
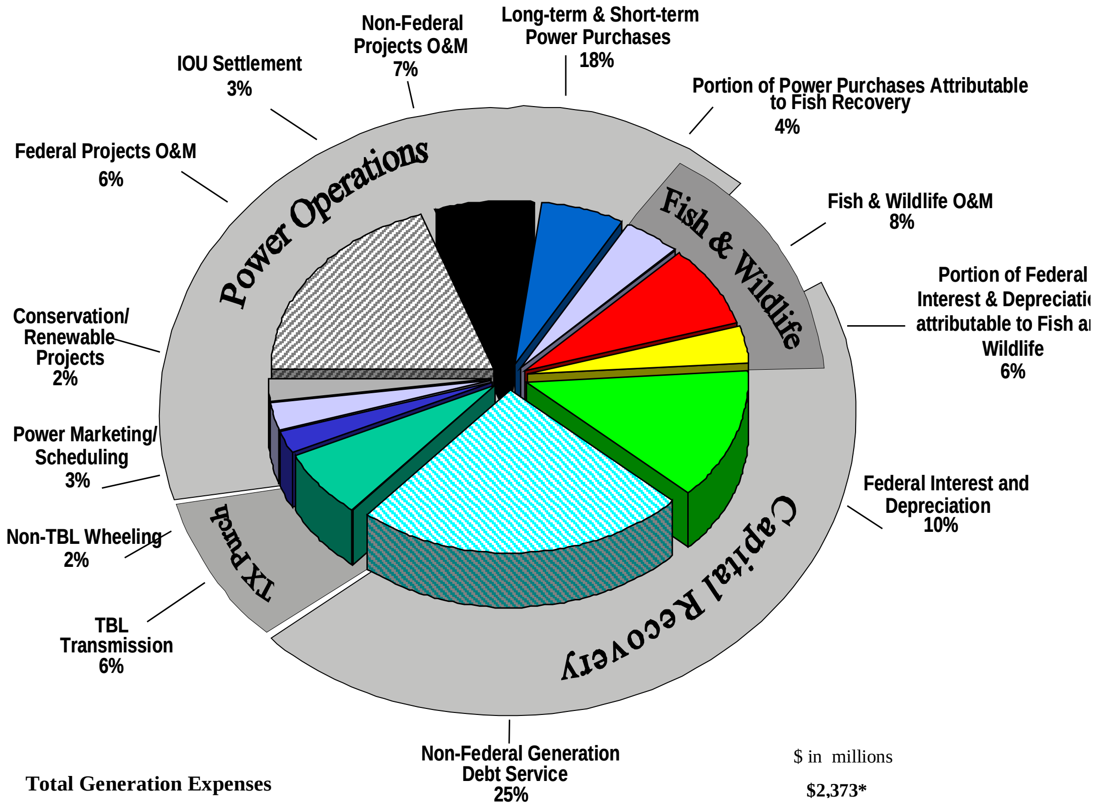


FIGURE 2

Composition of Generation
FY 2002-2006 Annual



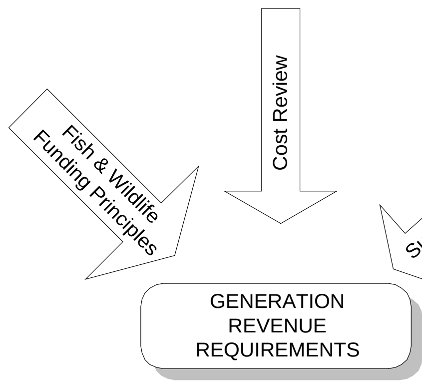
	$ in millions
Total Generation Expenses	**$2,373***
Power Operations	
Power Marketing/Scheduling	$64
Conservation/Renewable Projects	$54
Residential Exchange (IOU Settlement)	$70
Long-term & Short-term Power Purchases	$604
Non-Federal Projects O&M	$176
Federal Projects O&M	$175
Total	$1,143
Capital Recovery	
Federal Generation Interest and Depreciation	$386
Non-Federal Debt Service	$568
Total	$954
Fish and Wildlife	
Portion of Power Purchases Attributable to Fish and Wildlife Recovery**	$100
Portion of Fish & Wildlife O&M Attributable to Fish and Wildlife Recovery	$192
Portion of Federal Depreciation and Interest Attributable to Fish and Wildlife Recovery	$146
Total	$437
Transmission Purchases	
TBL Transmission	$137
Non-TBL Wheeling	$52
Total	$189

* Subtotals below do not add up to this total due to overlapping of some FLW expenses

* * Estimate

Note: This graphic shows expenses only, and does not include the planned net revenues component of revenue requirements. As such, the percentages above do not represent estimated impacts on rates.

1.2 Public Involvement Process



Public Processes and the Revenue Requirement

BPA participated in several major public processes that have had, and will continue to have, significant impacts on its methods and costs of doing business. The Cost Review had the objective of ensuring that BPA's near- and long-term generation and transmission costs are as low as possible consistent with sound business practices, thereby facilitating full cost recovery with power rates at or below market prices. *See* chapter 2 of the Revenue Requirement Study, WP-02-FS-BPA-02 for a chronology of the spending level development process. The Cost Review's recommendations form the basis of these revenue requirements (with the updates reflected in Appendix A of the Revenue Requirement Study, WP-02-FS-BPA-02).

Another public process resulted in the adoption of a set of Principles. The Principles are intended to "keep the options open" for future fish and wildlife decisions that may affect hydrosystem operations and to accommodate the Northwest Power Planning Council's (NWPPC) Fish and Wildlife Program to be released in early 2000. The Principles provide assumptions on fish and wildlife recovery funding levels that BPA is to include in its revenue requirements, specify a cost recovery goal, and establish guidelines for risk mitigation measures. *See* DeWolf *et al.*, WP-02-E-BPA-13.

BPA also conducted a public process to develop the Power Subscription Strategy. The Strategy addresses how those who receive the benefits of the region's low-cost Federal power should share a corresponding measure of the risks. It also seeks to implement the Subscription concept created by the Comprehensive Review in 1996 through contracts with regional customers for the sale of power and the distribution of Federal power benefits in the deregulated wholesale electricity market. Basic elements of the Subscription Strategy include the sale of power to meet the requirements of BPA's public agency customers while avoiding rate increases; a proposed settlement of the Residential Exchange Program (REP) with regional investor-owned utilities (IOU) that provides the equivalent of 1,800 average megawatt (aMW) of Federal power to residential and small farm consumers; sales to BPA's direct service industrial customers (DSI); fulfillment of BPA's fish and wildlife obligations while assuring a high probability of Treasury repayment; and providing market incentives for the development of conservation and renewables. *See* Burns *et al.,* WP-02-E-BPA-08.

These revenue requirements reflect savings recommended in the Cost Review, implement the Principles, and reflect the power purchases and residential exchange components of the Subscription Strategy.

2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

2.1 Development Process for Spending Levels

Development of spending program levels reflected in these revenue requirements began with the Comprehensive Review of the Northwest Energy Systems (Comprehensive Review), which the Governors of Idaho, Montana, Oregon, and Washington initiated in 1996 to seize opportunities and to moderate risks presented by the transition of the region's power system to a more competitive electricity market. The Comprehensive Review recognized that this transition raised fundamental issues for BPA, including long-term competitiveness and risks with up to 75 percent of BPA's firm revenues at stake due to expiration of long-term power contracts at the end of FY 2001.

A theme of the Comprehensive Review was that BPA and the other entities of the FCRPS must effectively manage and control costs. The recommendations specifically called on BPA to "pursue all actions possible in the short-term to cut costs." This was seen as essential to making the proposed Subscription-based system for marketing Federal power successful. A successful Subscription was viewed as the most certain means of achieving the goals of the Comprehensive Review, which were: adding no risk for the U.S. Treasury and third-party bondholders; fulfilling responsibilities for funding fish and wildlife recovery; and retaining the substantial long-term benefits of the FCRPS for the Northwest.

The Comprehensive Review also recommended that:

- BPA not acquire any additional resources to serve load growth, except on a bilateral contract basis, where the purchaser bears the risk;

- BPA's financial support of conservation acquisitions be limited to current contractual obligations and certain market development activities, provided they were self-sustaining by FY 1999;

- BPA limit its support for conservation market transformation in proportion to the share of regional firm loads served by BPA;

- BPA's net loss from renewable resource development be capped at $15 million per year; and

- the responsibilities and funding of the NWPPC be brought into line with the more limited role recommended for BPA.

An outgrowth of the Comprehensive Review was the Cost Review of the FCRPS (Cost Review). In September 1997, BPA and the NWPPC jointly launched a review of FCRPS costs. The objectives of the Cost Review were to ensure that BPA's long-term power and transmission costs would be as low as possible, consistent with sound business practices, enabling full cost recovery with power rates at or near market prices. 64 Fed. Reg. 44318, 44320 (1999). The intent of the Cost Review was to:

(1) give confidence to BPA customers, tribes, and constituents that future FCRPS costs would be managed effectively;

(2) ensure that the Subscription process resulted in a very high level of customer load commitment;

(3) minimize, if not avoid, transition (stranded) costs; and

(4) ensure that obligations to the U.S. Treasury, third-party bondholders, and fish and wildlife recovery would remain at least as secure as they are currently.

The Cost Review drew on the expertise of five executives with experience in managing large organizations undergoing competitive transitions. The Cost Review recommendations explicitly excluded fish and wildlife recovery costs. They also recognized that several categories of costs were subject to change in the rates development process, including short-term power purchase expenses, or net costs of the REP, General Transfer Agreement (GTA) costs, Federal interest, depreciation, and inter-business line expenses. The Cost Review panel addressed all other FCRPS costs to be recovered through BPA power and transmission rates, with a focus on power costs in the initial Subscription period, FY 2002-2006. A draft of the panel's recommendations went through a month-long regional public comment process, which included two broadly attended public meetings. In addition, there were briefings of other groups throughout the region, including tribal, public power, and environmental interests. The draft recommendations were modified to take into account comments received, and then submitted to the Administrator, the region's governors, the Northwest congressional delegation, and the House and Senate Committees on Appropriations in March 1998.

The recommendations outlined in the Cost Review were developed on an exception basis, using a cost baseline that already included significant cost control initiatives. These cost control initiatives included:

- eliminating or renegotiating all power resource acquisitions;

- achieving substantial reductions in WNP-2 operating costs, and continuing operation of the project only if economic;

- reengineering the Power Business Line (PBL) processes for efficiency and accountability;

- holding the PBL O&M costs, including costs for the other entities in the FCRPS, constant in nominal dollars over the nine-year planning horizon;

- substantially reducing PBL and corporate FTE levels, both Federal and contractor;

- reducing administrative and program costs in the REP through settlement agreements;

- constraining losses due to renewable resource investments;

- reducing energy efficiency/conservation program costs, with a goal of achieving financial self-sufficiency by shifting from centrally procured incentives-based programs to approaches that are more market-driven; and by reducing Energy Efficiency staffing over the next four years;

- pursuing direct funding for future U.S. Army Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) O&M expenses, as well as revenue-producing investments;

- constraining BPA-funded Federal investments to levels commensurate with availability of low-cost sources of capital;

- redesigning information technology and accounting/financial reporting system and services to be more responsive and less costly; and

- reducing the costs of the NWPPC.

These efforts had begun to yield substantial reductions in costs by the time BPA received the recommendations of the Cost Review. The Cost Review Committee recommended that BPA undertake extraordinary efforts in its power, corporate, and transmission organizations to reduce the costs of its commercial operations and constrain the costs of its public benefit programs. Similarly, the Cost Review Committee recommended that other members of the FCRPS--COE, Reclamation, and Energy Northwest--act in concert with BPA by taking aggressive action to maximize the value of the FCRPS by reducing O&M costs and improving asset productivity. The specific recommendations were built on, or took exception to, the cost baseline:

(1) Further reduce staffing and support costs of power marketing and other PBL functions not directly related to the operation of Federal power system through efficiency and reoriented long-term marketing efforts.

(2) Fund regional conservation market transformation at a level proportional to the percent of regional firm load served by BPA, consistent with the recommendations of the Comprehensive Review.

(3) Reduce projected legacy conservation contract expenses to reflect historical underspending.

(4) Further reducing funding for the NWPPC to reflect changes in BPA's regional role, the NWPPC's role as recommended by the Comprehensive Review, and the continued importance of fish and wildlife issues.

(5) Provide funding for costs of the three renewable resource projects that BPA currently was planning and for currently planned levels of renewable resource data collection and research and development.

(6) Develop and implement a consolidated, integrated capital/asset management strategy for Federal hydro directed at maximizing value, including both financial returns and public benefits.

(7) Implement a strategy for WNP-2 that combines aggressive cost management with a flexible response to market conditions and unforeseen costs.

(8) Further reduce the cost of BPA's administrative and other internal support costs, including financial, human resources, information management, procurement, strategic planning, public affairs, legal services, and other internal service costs, to an aggregate 50 percent of 1996 actual levels.

(9) Obtain legislative changes in the areas of personnel management and procurement to improve administrative flexibility and the ability to manage internal costs.

(10) Further reduce the Transmission Business Line's (TBL) internal O&M expenses through between the Power and Transmission Business Lines.

(11) Conform to Federal Power Act requirements, adjusting and correcting functionalization of costs between the Power and Transmission Business Lines.

(12) Further reduce Federal and non-Federal debt service expenses through refinancings, greater reliance on variable rate debt, and other debt reduction actions.

(13) Account for previously identified "undistributed reductions."

For FCRPS activities as a whole, including power and transmission, the sum of these recommended cost reductions and efficiency gains was estimated at $136.9 million on average annually over the five-year period, FY 2002-2006. For the PBL the reductions and gains were estimated to be $145.7 million on average annually over the same five-year period. For additional information about these recommendations and the Cost Review, *see* Appendix A of the Revenue Requirement Study, WP-02-FS-BPA-02.

In June 1998, BPA began a public involvement process entitled Issues '98. Issues '98 was designed to provide the region an overview and context for major policy issues surrounding BPA's future, including cost management. In addition to taking written comment, three public meetings were held within the region to provide an opportunity for the public to participate. BPA notified process participants that Issues '98 was their opportunity to comment on BPA's proposed implementation plan of the Cost Review recommendations. At the conclusion of the Issues '98 process, BPA completed and released the "Cost Review Implementation Plan." This document, published in October 1998, summarized the 13 recommendations of the Cost Review, the implementation plan, and relevant customer comments. This Study reflects the "Cost Review Implementation Plan," with key caveats. *See* Appendix A for a copy of the document and “Updates to Forecast of Generation Expenses.” The caveats covered two cost areas that were subject to change outside the Cost Review.

As the first caveat, several cost components were noted as subject to change as BPA developed its rate proposal, namely, short-term power purchase expense, net costs of the REP, GTA costs, Federal interest and depreciation, and inter-business line expenses. Implementation of the Subscription Strategy, as explained in Burns *et al.*, WP-02-E-BPA-08, has resulted in substantially higher expense estimates for the power purchases necessary to balance power output and augment the system to meet forecasted firm power sales. The Subscription Strategy also includes a proposed settlement of the REP that incorporates both a power and financial component. GTA and inter-business line expenses estimates have also been updated for this final rate proposal.

As the second caveat, the fish and wildlife funding amount shown in Issues ‘98 did not include operational costs (*i.e*., power purchases related to fish recovery) and did not reflect averages of the range of system configuration alternative costs for O&M and capital called for in the Principles.

Combined, the cost changes since Issues ‘98 have resulted in average annual expenses to $2,358 million, an increase of $489 million over the forecast for Issues ‘98. More detail of the expense changes since Issues ‘98 can be found in Appendix A of this document and in DeWolf *et al.*, WP-02-E-BPA-13.

The cost cuts recommended by the Cost Review and reflected in the spending levels are expected to be difficult to achieve. As a result, some probability that the cost cuts will not be fully realized has been reflected in BPA’s Non-Operating Risk Modeling (NORM). For additional information on NORM, *see* Chapter 3, Risk Analysis Study, WP-02-FS-BPA-03 and Lovell *et al.*, WP-02-E-BPA-15.

2.2 Financial Risk Mitigation

BPA adopted a long-term policy in its 1993 Final Rate Proposal calling for setting rates that build and maintain financial reserves sufficient for the agency to achieve a 95 percent probability of meeting U.S. Treasury payments in full and on time for each two-year rate period. *See* 1993 Final Rate Proposal, Administrator's Record of Decision (ROD), WP-93-A-02, at 72. In the 1996 rate case, this 95 percent, two-year standard was "converted" to an equivalent 88 percent probability of making all five U.S. Treasury payments in a five-year period.

$$.95^{1/2} = .975$$

$$.975^{5} = .88$$

Since then, both the Comprehensive Review (discussed in section 2.1) and the Principles have highlighted the need for a high TPP. The Comprehensive Review recommendations were developed with three goals in mind. One of these goals was to "ensure repayment of the debt to the U.S. Treasury with a greater probability than currently exists . . ." The Principles specify that . . .

> "Bonneville will demonstrate a high probability of Treasury payment in full and on time over the five-year period.
>
> - A 100 percent probability of Treasury payment is not achievable, but BPA's new rates must be designed to maintain or improve TPP, even in view of the range of fish costs.

- BPA will demonstrate a probability of Treasury payment in full and on time over the five-year rate period at least equal to the 80 percent level established in the last rate case and will seek to achieve an 88 percent level." *See* the Principles, Volume 1, Chapter 13 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.

In this rate proposal, BPA has analyzed its power risks and is proposing risk mitigation tools designed to achieve the 88 percent probability standard for the generation function. To achieve this TPP, the following risk mitigation "tools" are included in the ToolKit model:

(1) Starting Reserves: Starting financial reserves include cash in the BPA Fund and the deferred borrowing balance attributed to the generation function. The risk-adjusted values for starting reserves is projected to average $842 million at the beginning of FY 2002.

(2) Credits under the Fish Cost Contingency Fund (FCCF): Under the Northwest Power Act, the Administrator makes expenditures from the BPA Fund to protect, mitigate, and enhance fish and wildlife that are affected by Federal hydro. These costs are then allocated to the hydro projects and project purposes, including nonpower purposes. So that ratepayers pay no more than the power share of fish and wildlife costs, the Northwest Power Act directs BPA to recoup its funding of nonpower purposes via section 4(h)(10)(C) credits, which are implemented by reducing annual cash transfers to Treasury. Because they effectively serve as a source of cash, the credits are accounted for as revenue and are included in the revenue forecast. *See* chapter 5.2.3.3 of the Wholesale Power Rate Development Study, WP-02-FS-BPA-05. The formula for calculating the credit is 27 percent of:

- BPA annual fish and wildlife program expenses and capital expenditures; and

- Power purchases and fish and wildlife recovery net of resale revenues.

The FCCF is comprised of section 4(h)(10)(C) credits that BPA has earned prior to 1994 but has yet to exercise. The current balance of the "fund" is $325 million. The terms of the agreement between BPA and the Administration for access to these credits were first described in an October 24, 1995, letter from the Office of Management and Budget (OMB) Director, Alice Rivlin to Senator Mark Hatfield and formalized in an interagency Memorandum of Agreement (MOA) dated September 13, 1996. This MOA expires in FY 2001. *See* Volume 1, Chapter 13 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A. Under the MOA, BPA may use the FCCF to defray fish and other water-related costs if:

- higher costs are incurred than the MOA assumed because of court action;

- higher costs are incurred due to adverse water conditions (criteria designed to trigger access 25 to 30 percent of time); or

- a fisheries emergency is declared.

Administration commitments in the Principles confirm that current terms of access to the FCCF will be extended to the FY 2002-2006 rate period. *Id.* Use of the FCCF credits are accounted for as revenue. The revenue forecast includes a probabilistic estimate of the annual use of these credits. *See* Volume 1, Chapter 12 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A; Chapter 5.2.3.3, Revenue

Forecast in Wholesale Power Rate Development Study, WP-02-FS-BPA-05; Conger *et al.*, WP-02-E-BPA-15.

(3) Cost Recovery Adjustment Clause (CRAC): The CRAC adjusts posted wholesale power rates upward if actual accumulated net revenues attributable to the generation function fall below the thresholds shown in Table 3. The CRAC is applicable to Priority Firm Power (PF) [Preference (excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02) including under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index rate, Residential Load (RL-02) including the financial portion of any Residential Exchange Settlement under this rate schedule, and New Resources Firm Power (NR-02) rate schedules, as well as Subscription purchases under the Firm Power Products and Services (FPS) rate schedule. It is not applicable to Pre-Subscription contracts, Slice loads, the TAC portion of the PF rate, nor the PF Targeted Adjustment Charge (TAC) or PF TACUL loads. The CRAC may trigger as frequently as each year of the five-year rate period. The adjustment would be applied to power deliveries beginning the April following the FY in which the threshold was passed. Any such increase in FY 2002-2005 would remain in effect through March of the following year. During the final FY of the rate period (2006) the rate would remain in effect through September 2006. The level of planned rate increase is limited to the lower of the annual Maximum Planned Recovery Amount in table 3 below, or the amount by which accumulated net revenues underrun the threshold. *See* Volume 1, Chapter 12 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A; the rate schedule for CRAC; and Lovell *et al.*, WP-02-E-BPA-14.

Table 3

CRAC Trigger Thresholds and Annual Caps

End of Fiscal Year	Reserves Equivalent to Threshold	Threshold (AANR*)	Maximum Planned Recovery Amount (beginning in following April)
2001	$300M	-$350M	$125M
2002	$300M	-$350M	$135M
2003	$500M	-$250M	$150M
2004	$500M	-$250M	$150M
2005	$500M	-$250M	$87.5M

* Accumulated net revenues attributable to generation function.

(4) Planned Net Revenues for Risk (PNRR). PNRR is a component of the revenue requirement that is added to annual expenses. PNRR adds to cash-flows so that financial reserves, in conjunction with other risk mitigation tools, achieves the TPP goal.

ToolKit Model

The ToolKit Model is used to determine the probability of making all planned Treasury payments during the five-year rate period given the risks identified in Risk Analysis Model (RiskMod) and NORM (*see* Risk Analysis Study, WP-02-FS-BPA-03), and the risk mitigation tools. ToolKit is part of a larger system of models that includes RiskMod. The RiskMod is the successor to the Short-Term Evaluation and Analysis Model (STREAM) model that was used by BPA in previous rate cases. Like STREAM, RiskMod is used to develop distributions of the generation function net revenues that reflect *operating* risks--hydro and thermal generation performance, California market prices, Southwest gas prices, and generating and non-generating public utility load uncertainty. As a counterpart to RiskMod, NORM produces cost distributions that reflect the impact of *non-operating* risks that PBL is facing in the FY 2002-2006 rate period. These non-operating risks include, but are not limited to, fish and wildlife O&M and capital recovery expenses, and other expenses. Both RiskMod and NORM are discussed in greater detail in the Risk Analysis Study, WP-02-FS-BPA-03.

ToolKit is used to demonstrate BPA's ability to meet the 88 percent TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. More specifically, ToolKit is used to assess the effects of various policies and risk mitigation measures on the level of end of year reserves attributable to generation, with a deferral of Treasury payment occurring when these reserves fall below $50 million.

Thirteen (13) distinct, equally weighted, alternative fish operations are taken into account in the risk distributions used by the ToolKit model. Five of these 13 Fish and Wildlife Alternatives reflect a 90 percent - 10 percent weighting of adjusted and unadjusted schedules of implementation, respectively. *See* Volume 1, Chapter 13 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A. The ToolKit evaluated 3,900 separate five-year net revenue scenarios (300 per Fish and Wildlife Alternatives), assuming a starting reserves balance of $842.3 million. The model indicates that $98 million per year of PNRR would be needed to achieve the desired 88 percent TPP standard, resulting in an expected value of $1.268 billion for FY 2006 ending reserves. Both section 4(h)(10)(C) and FCCF credits were modeled in RiskMod for the FY 2002–2006 rate period, while ToolKit was used to assess the effects of the section 4(h)(10)(C) credits for the remainder of the current rate period. *See* Volume 1, Chapter 12 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A for further discussion of the ToolKit Model and the FCCF.

BPA is also proposing criteria for distributing "dividends" to certain stakeholders if Audited Accumulated Net Revenues (AANR) reach the Dividend Distribution Clause (DDC) Threshold of $250 million, and if a five-year forecast shows that BPA's TPP standard of 88 percent (or equivalent replacement financial criterion) would still be met. BPA intends to conduct a public process by October 1, 2001, to determine how any distribution will be allocated among stakeholders during the rate period. The first $15 million will be allocated to qualifying Conservation and Renewable purposes. The remaining dividend amount, if any, will be allocated to other stakeholders, one of which will be power customers. The distribution of any amounts to power customers would be made through credits to their power bills. *See* DeWolf *et al.*, WP-02-E-BPA-13 and WP-02-E-BPA-39.

2.3 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 $1,322 million for the FY 2002-2006 rate period and $2,447 million for the FY 1999-2006 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, habitat construction, supplementation construction, gas abatement, and mainstem passage; and

- investment in ADP and other capital equipment.

Sources of Capital, FY 2002-2006

($ in millions)

Investments in fish and wildlife recovery	
Bonds Issued to U.S. Treasury	177
Federal Appropriations [1]	587
	764
Investments in revenue producing assets	
Bonds Issued to U.S. Treasury	390
Federal Appropriations *	144
Non-Federal Debt	24
	558
Total	1,322

* Reflects projected plant-in-service, not Congressional appropriations for the period.

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

Bonds Issued to the Treasury

This source of capital will be used to finance FY 2002-2006 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 $567 million in BPA Fish and Wildlife "direct" Program investments ($177 million), and generating resource investments of the COE and Reclamation ($390 million) during FY 2002–2006.

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

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 investments are projected to total $731 million during the rate period, including $587 million in COE investments for fish and wildlife recovery and the $144 million for generating resource additions and replacements. Capital investments funded by this source do not become an obligation until placed in service.

"The Bonneville Appropriations Refinancing Act" (the Refinancing Act) was enacted in April 1996. This Refinancing Act reset the unpaid principal of FCRPS appropriations and reassigned interest rates. New principal amounts were established at the beginning of FY 1997, at the present value of the principal and annual interest payments BPA would make to the Treasury for these obligations in the absence of the Refinancing Act, plus $100 million. The Refinancing Act restricted prepayment of the new principal to $100 million in the FY 1997-2001 period. Other repayment terms and conditions were unaffected. The Refinancing Act also specifies that BPA's annual payments to the Confederated Tribes of the Colville Reservation be treated as a credit against its annual payment to Treasury. The legislation included a provision directing BPA to offer a contractual commitment to its customers that the appropriations repayment obligations will not be increased in the future.

The interest rate forecast for appropriated capital investments expected to be placed in service is found in Volume 1, Chapter 7 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A. Practices for assigning interest rates to new appropriations investment and for determining interest during construction were changed by the Refinancing Act. Each new capital investment is assigned a rate from the Treasury yield curve prevailing in the month prior to the beginning of the FY in which the new investment is placed in service.

In determining interest during construction for new capital investments, for each FY of construction the prevailing Treasury one year rate 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* Chapter 5 of the Revenue Requirement Study, WP-02-FS-BPA-02 and Volume 1, Chapter 9 of Revenue Requirement Study Documentation, WP-96-FS-BPA-02A.

Third-Party Debt

Third-party debt differs from Treasury debt in that entities other than BPA or 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, –2, and –3 nuclear power projects, and the Lewis County Public Utility District Hydroelectric (Cowlitz Falls). This Study includes $10 million in projected WNP-2 additions and replacements to be financed by Energy Northwest during the cost evaluation period.

Table 4
FEDERAL COLUMBIA RIVER POWER SYSTEM (FCRPS)
PROJECTED CAPITAL FUNDING REQUIREMENTS FOR THE POWER BUSINESS LINE
2002 FINAL RATE PROPOSAL
(Annual Outlays in Millions of Dollars)

	Actual	Current Rate Period						Next Rate Period					
	Average FYs 90-97	Actual FY 97	Actual FY98	Actual FY 99	FY 2000	FY 2001	Average FY 97-'01	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	Average FYs '02-'06
OWER													
apital Requirements for Revenue Producing Investments													
Corps & Bureau Additions/Replacements - Direct Funded	11.1	19.6	28.0	28.0	80.9	76.1	46.5	89.9	86.7	61.7	62.1	62.1	72.5
Corps & Bureau Additions/Replacements - Appropriations[1]	45.3	59.7	0.0	30.0	20.7	35.6	29.2	23.9	36.4	21.3	31.3	31.3	28.8
PBL Capital Equipment	N/A	0.0	2.6	11.0	3.0	3.0	3.9	2.0	2.0	2.0	2.0	2.0	2.0
Capitalized Bond Premium	0.0	0.0	7.1	0.0	8.4	3.0	3.7	5.2	3.0	3.0	3.0	3.0	3.4
WNP-2: Additions/Replacements	42.5	11.0	12.2	9.5	5.3	5.7	8.7	5.7	4.4	4.6	4.7	4.7	4.8
Other Non - Federal	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
nnual Capital Requirements for Revenue Producing Investments	**100.4**	**90.3**	**49.9**	**78.4**	**118.3**	**123.4**	**92.1**	**126.7**	**132.5**	**92.6**	**103.1**	**103.1**	**111.6**
umulative Capital Requirements for Rev Producing Investments		**90.3**	**140.2**	**218.6**	**336.9**	**460.3**		**126.7**	**259.1**	**351.7**	**454.8**	**557.9**	
apital Requirements for Non-Revenue Producing and Public Benefit Investments													
Energy Conservation	63.1	20.5	14.3	12.6	1.0	1.0	9.9	0.0	0.0	0.0	0.0	0.0	0.0
Fish Investment													
BPA Fish and Wildlife Investment[2]	21.2	28.1	22.0	14.7	27.0	27.0	23.8	34.7	38.3	35.8	34.0	34.2	35.4
Corps & Bureau Fish Investment - Appropriations[2]	23.7	(32.9)[3]	0	20.7	4.5	468.9	92.2	111.8	44.7	213.6	91.2	125.9	117.4
Total Fish Investment	44.9	(4.8)	22	35.4	31.5	495.9	116.0	146.5	83.0	249.4	125.2	160.1	152.8
Other Third Party	47.7[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
nnual Capital Req. for Non-Rev. & Public Benefit Invests.	**155.7**	**15.7**	**36.3**	**48.0**	**32.5**	**496.9**	**125.9**	**146.5**	**83.0**	**249.4**	**125.2**	**160.1**	**152.8**
umulative Capital Req. for Non-Rev. & Public Benefit Invest.		**15.7**	**52.0**	**100.0**	**132.5**	**629.4**		**146.5**	**229.5**	**478.9**	**604.1**	**764.2**	
NNUAL FUNDING REQUIREMENTS FOR POWER	**256.1**	**106.0**	**86.2**	**126.4**	**150.8**	**620.3**	**217.9**	**273.2**	**215.5**	**342.0**	**228.3**	**263.2**	**264.4**
UMULATIVE FUNDING REQUIREMENTS FOR POWER		**106.0**	**192.2**	**318.6**	**469.4**	**1,089.7**		**273.2**	**488.6**	**830.6**	**1,058.9**	**1,322.1**	

OOTNOTES:
Reflects plant in service, including IDC, not expenditures.
Reflects annual average of the plant-in-service in all 13 scenarios.
Reflects transfer from PIS to CWIP of $42.9 million related to Mitigation Analysis.
Includes Northern Wasco, CARES Conservation, Cowlitz Falls, and Tacoma Conservation

3. DEVELOPMENT OF REPAYMENT STUDIES

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 five years in the rate test period, FY 2002–2006. 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 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 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. Most 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 Treasury.

Bonds are issued to finance BPA conservation, fish and wildlife programs, and COE and Reclamation investments direct-funded by BPA, and repaid within the provisions of each bond agreement with the Treasury. Bonds to finance fish and wildlife capital investments are issued with maturities not to exceed 15 years, the same period over which BPA amortizes these capital investments. Conservation bonds are issued with maturities not to exceed 20 years, consistent with the period over which BPA amortizes these capital investments. COE and Reclamation direct-funding bonds are issued with maturities not to exceed 45 years.

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-02-FS-BPA-02; and in Volume 2, Chapter 11 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02B. *See* chapter 5 of the Revenue Requirement Study, WP-02-FS-BPA-02, for an explanation of repayment policies and requirements.

4. FY 1999 GENERATION REVENUE REQUIREMENTS

This chapter explains the cost accounting formats used to develop revenue requirements for FY 2002–2006. Section 4.1.1 provides a line-by-line description of the Revenue Requirement Income Statement and section 4.1.2 provides a line-by-line description of the Revenue Requirement Statement of Cash-Flows.

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 to 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 24), Minimum Required Net Revenues (Line 26), and PNRR (Line 27). The sum of these four major components is the Total Revenue Requirement (Line 29).

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

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-02-FS-BPA-02B provides additional information on the development and use of the data contained in the tables.

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

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

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

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

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

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

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

Residential Exchange Program (REP) (Line 10). Under the REP, as provided in section 5(c) of the Northwest Power Act, 16 U.S.C. §839c(c), BPA purchases power from a participating utility at the utility's Average System Cost (ASC). BPA then sells an equivalent amount of power to the utility at BPA's applicable PF rate. The REP provides regional utilities' residential and small farm customers with benefits of the Federal power system. The exchange of power is not a conventional power transaction. No power is actually transferred to or from BPA under the Program; rather, participating utilities receive benefit payments from BPA that represent the difference between "selling high" to BPA and "buying low" from BPA. BPA's rate development methodology has been based on the gross costs of the program. *See* Volume 1, Chapter 4 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.

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

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

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

Amortization of Conservation Investment (Line 14). Amortization of Conservation is the annual expense associated with the writeoff of BPA's investments in energy conservation measures. The annual conservation writeoff is calculated using the straight line method of depreciation over an expected life of 20 years. *See* Volume 1, Chapters 4 and 5 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.

Federal Projects Depreciation (Line 15). Depreciation is the annual capital recovery expense associated with FCRPS plant-in-service. Reclamation and COE (including Lower Snake River Fish and Wildlife Compensation Plan) plant, including assets for fish and wildlife recovery, is depreciated by the straight line method of calculation, using the average service life of each project. Capital equipment (office furniture and fixtures and data processing hardware and software) is also depreciated by the straight line method using the average service life for the categories of capital investment. *See* Volume 1, Chapters 4 and 5 of Revenue Requirement Study Documentation, WP-02-FS-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 BPA, COE, and Reclamation appropriations as determined in the generation repayment studies. *See* Volume 1, Chapters 4, 6, and 9 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.

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

Interest Credit on Cash Reserves (Line 21). An interest income credit is also computed on the projected yearend cash balance in the BPA fund attributable to the Power Marketing function that carry over into the next year. It is credited against bond interest. *See* Volume 1, Chapter 6 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.

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

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

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

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

Minimum Required Net Revenues (Line 26). Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash-Flows (Table 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 A2.

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

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

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

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 Revenue Requirement Study Documentation, WP-02-FS-BPA-02A and WP-02-FS-BPA-02B, provide additional information related to the use and development of the data contained in table.

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

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

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

Capitalization Adjustment (Line 6). Capitalization Adjustment is from the Income Statement (Table 5A, Line 22). It is a non-cash (contra) expense. *See* Volume 1, Chapter 8 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A.

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

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

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

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

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

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

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

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

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

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

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

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

Planned Net Revenues for Risk (PNRR) (Line 22). PNRR reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 5A, Line 27).

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

4.2 Current Revenue Test

Consistent with RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test (*see* Tables 6 and 7) determines whether the revenues expected from current rates can continue to meet cost recovery requirements and, therefore, be extended. However, due to the significant restructuring of BPA's wholesale power products and services under Subscription and the resulting changes in contracts, as well as BPA's need to implement the Principles, it is not relevant whether current rates could superficially satisfy cost recovery requirements.

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 the U.S. TPP risk goal for the rate approval 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 approval period of FY 2002 through 2006.

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).

Table 8B, Statements of Cash-Flows, tests the sufficiency of the resulting Net Revenues from Table 8A (Line 27) 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 21). As explained in section B.2, the annual cash-flow

(Line 21) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash requirements.

Under Subscription, the REP has been replaced by a power sale to and a financial settlement with the participating utilities. *See* Leathly *et al.,* WP-02-E-BPA-19.

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 year 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.

TABLE 5A
GENERATION REVENUE REQUIREMENT
INCOME STATEMENT
($thousands)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	OPERATING EXPENSES:					
2	OPERATION & MAINTENANCE	469,614	453,220	446,510	441,161	438,260
3	PURCHASE AND EXCHANGE POWER-					
4	SHORT-TERM POWER PURCHASES	457,608	485,266	449,626	487,688	487,457
5	LONG-TERM POWER PURCHASES	65,904	66,159	66,450	66,977	67,414
6	TROJAN	19,547	14,154	12,564	12,589	12,609
7	WNP NO. 1	178,104	168,240	175,007	168,294	180,376
8	WNP NO. 2	351,536	408,804	404,348	361,649	391,800
9	WNP NO. 3	156,806	156,162	152,401	152,649	151,006
10	RESIDENTIAL EXCHANGE PROGRAM	0	0	0	0	0
11	BPA FISH & WILDLIFE O&M	131,700	138,000	140,100	142,900	144,400
12	AMORTIZATION OF BPA FISH & WILDLIFE INVESTMENT	19,772	21,842	23,737	25,394	26,407
13	CONSERVATION	34,929	33,340	33,640	34,040	34,340
14	AMORTIZATION OF BPA CONSERVATION INVESTMENT	59,337	55,586	47,125	43,179	37,650
15	FEDERAL PROJECTS DEPRECIATION	97,608	100,773	103,661	106,003	108,403
16	TOTAL OPERATING EXPENSES	2,042,463	2,101,545	2,055,169	2,042,523	2,080,121
17	INTEREST EXPENSE:					
18	INTEREST ON FEDERAL INVESTMENT-					
19	ON APPROPRIATED FUNDS	252,003	255,597	261,715	267,926	268,119
20	ON LONG-TERM DEBT	63,472	67,412	72,664	77,374	80,178
21	INTEREST CREDIT ON CASH RESERVES	(61,063)	(67,549)	(75,054)	(79,878)	(84,818)
22	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
23	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(2,992)	(2,890)	(2,050)	(2,056)	(2,044)
24	NET INTEREST EXPENSE	203,682	205,042	209,400	218,576	216,645
25	TOTAL EXPENSES	2,246,145	2,306,587	2,264,569	2,261,099	2,296,766
26	MINIMUM REQUIRED NET REVENUES 1/	0	0	0	18,311	806
27	PLANNED NET REVENUES FOR RISK	98,000	98,000	98,000	98,000	98,000
28	TOTAL PLANNED NET REVENUES (26+27)	98,000	98,000	98,000	116,311	98,806
29	**TOTAL REVENUE REQUIREMENT**	**2,344,145**	**2,404,587**	**2,362,569**	**2,377,410**	**2,395,572**

1/ SEE NOTE ON CASH FLOW TABLE.

TABLE 5B
GENERATION REVENUE REQUIREMENT
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	CASH FROM CURRENT OPERATIONS:					
2	MINIMUM REQUIRED NET REVENUES 1/	0	0	0	18,311	806
3	EXPENSES NOT REQUIRING CASH:					
4	FEDERAL PROJECTS DEPRECIATION	97,608	100,773	103,661	106,003	108,403
5	AMORTIZATION OF CONSERVATION/F&W INVESTMENT	79,109	77,428	70,862	68,573	64,057
6	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
7	CASH PROVIDED BY CURRENT OPERATIONS	128,979	130,673	126,648	148,097	128,476
8	CASH USED FOR CAPITAL INVESTMENTS:					
9	INVESTMENT IN:					
10	UTILITY PLANT	(228,000)	(168,700)	(297,500)	(185,525)	(220,225)
11	CONSERVATION	0	0	0	0	0
12	FISH & WILDLIFE	(34,732)	(38,317)	(35,825)	(33,988)	(34,182)
13	CASH USED FOR CAPITAL INVESTMENTS	(262,732)	(207,017)	(333,325)	(219,513)	(254,407)
14	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:					
15	INCREASE IN LONG-TERM DEBT	127,032	125,917	98,425	97,013	97,207
16	REPAYMENT OF LONG-TERM DEBT	(66,000)	(25,622)	(27,400)	(30,757)	0
17	INCREASE IN CONGRESSIONAL CAPITAL APPROPRIATIONS	135,700	81,100	234,900	122,500	157,200
18	REPAYMENT OF CAPITAL APPROPRIATIONS	(41,401)	(47,362)	(64,885)	(117,340)	(128,476)
19	PAYMENT OF IRRIGATION ASSISTANCE	0	0	(739)	0	0
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	155,331	134,033	240,301	71,416	125,931
21	ANNUAL INCREASE (DECREASE) IN CASH	21,578	57,689	33,624	0	0
22	PLANNED NET REVENUES FOR RISK	98,000	98,000	98,000	98,000	98,000
23	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	119,578	155,689	131,624	98,000	98,000

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

TABLE 6A
GENERATION CURRENT REVENUE TEST
INCOME STATEMENT
($thousands)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	REVENUES FROM CURRENT RATES	2,429,851	2,441,742	2,399,756	2,423,446	2,436,039
2	OPERATING EXPENSES:					
3	OPERATION & MAINTENANCE	466,468	450,818	444,424	439,716	437,458
4	PURCHASE AND EXCHANGE POWER-					
5	SHORT-TERM POWER PURCHASES [1]	507,113	513,714	474,771	510,830	502,206
6	LONG-TERM POWER PURCHASES	65,904	66,159	66,450	66,977	67,414
7	TROJAN	19,547	14,154	12,564	12,589	12,609
8	WNP NO. 1	178,104	168,240	175,007	168,294	180,376
9	WNP NO. 2	351,536	408,804	404,348	361,649	391,800
10	WNP NO. 3	156,806	156,162	152,401	152,649	151,006
11	RESIDENTIAL EXCHANGE - IOU SETTLEMENT	69,658	69,658	69,658	69,658	69,658
12	FISH & WILDLIFE	131,700	138,000	140,100	142,900	144,400
13	AMORTIZATION OF FISH & WILDLIFE	20,589	22,659	24,554	26,211	27,224
14	CONSERVATION	34,929	33,340	33,640	34,040	34,340
15	AMORTIZATION OF CONSERVATION	59,413	55,662	47,201	43,255	37,726
16	FEDERAL PROJECTS DEPRECIATION	95,288	97,910	100,170	102,215	104,164
17	TOTAL OPERATING EXPENSES	2,157,053	2,195,279	2,145,288	2,130,983	2,160,380
18	INTEREST EXPENSE:					
19	INTEREST ON FEDERAL INVESTMENT-					
20	ON APPROPRIATED FUNDS	252,003	255,597	261,715	267,926	268,119
21	ON LONG-TERM DEBT	63,472	67,412	72,664	77,374	80,178
22	INTEREST CREDIT ON CASH RESERVES	(57,122)	(62,765)	(67,863)	(71,399)	(74,131)
23	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
24	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(2,992)	(2,890)	(2,050)	(2,056)	(2,044)
25	NET INTEREST EXPENSE	207,623	209,826	216,591	227,055	227,332
26	TOTAL EXPENSES	2,364,676	2,405,105	2,361,879	2,358,038	2,387,712
27	NET REVENUES	65,175	36,637	37,877	65,408	48,328

[1] System Augmentation	252,064	290,218	253,541	292,433	279,789
Balancing Power Purchases	205,544	195,048	196,085	195,255	207,668

TABLE 6B
GENERATION CURRENT REVENUE TEST
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	CASH FROM CURRENT OPERATIONS:					
2	NET REVENUES	65,175	36,637	37,877	65,408	48,328
3	EXPENSES NOT REQUIRING CASH:					
4	FEDERAL PROJECTS DEPRECIATION	95,288	97,910	100,170	102,215	104,164
5	AMORTIZATION OF CONSERVATION/F&W INVESTMENT	80,002	78,321	71,755	69,466	64,950
6	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
7	CASH PROVIDED BY CURRENT OPERATIONS	192,727	165,340	161,927	192,299	172,652
8	CASH USED FOR CAPITAL INVESTMENTS:					
9	INVESTMENT IN:					
10	UTILITY PLANT	(228,000)	(168,700)	(297,500)	(185,525)	(220,225)
11	CONSERVATION	0	0	0	0	0
12	FISH & WILDLIFE	(34,732)	(38,317)	(35,825)	(33,988)	(34,182)
13	CASH USED FOR CAPITAL INVESTMENTS	(262,732)	(207,017)	(333,325)	(219,513)	(254,407)
14	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:					
15	INCREASE IN LONG-TERM DEBT	127,032	125,917	98,425	97,013	97,207
16	REPAYMENT OF LONG-TERM DEBT	(66,000)	(25,622)	(27,400)	(30,757)	0
17	INCREASE IN CONGRESSIONAL CAPITAL APPROPRIATIONS	135,700	81,100	234,900	122,500	157,200
18	REPAYMENT OF CAPITAL APPROPRIATIONS	(41,401)	(47,362)	(64,885)	(117,340)	(128,476)
19	PAYMENT OF IRRIGATION ASSISTANCE	0	0	(739)	0	0
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	155,331	134,033	240,301	71,416	125,931
21	ANNUAL INCREASE (DECREASE) IN CASH	85,326	92,356	68,903	44,202	44,176

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

	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 (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 2/		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 3/		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	2,686,700	319,400	1,938,000	136,000	216,600	76,700	136,000	212,700	196,544		16,156
1996	2,744,510	383,699	1,942,515	151,122	208,509	58,665	151,122	194,787 /4	135,010		59,777
1997	1,996,439	612,961	924,789	148,215	197,238	113,236	104,632	217,868	80,200	25,143	112,525
1998	2,060,750	665,005	1,091,678	162,562	201,930	(60,425)	118,440	58,015	61,000		(2,985)
1999	2,366,423	702,717	1,196,308	162,008	182,079	123,311	117,886	241,197	25,000		216,197
COST EVALUATION PERIOD											
2000	2,249,174	744,261	1,037,166	164,030	179,390	124,327	116,275	240,602	90,431		150,171
2001	2,181,778	711,185	1,014,519	169,530	203,938	82,606	121,538	204,144	53,787	16,560	133,797
RATE APPROVAL PERIOD											
2002	2,429,851	633,096	1,348,667	175,290	207,623	65,175	127,552	192,727	107,401		85,326
2003	2,441,742	622,157	1,396,891	176,231	209,826	36,637	128,703	165,340	72,984		92,356
2004	2,399,756	618,163	1,355,200	171,925	216,591	37,877	124,050	161,927	92,285	739	68,903
2005	2,423,446	616,656	1,342,646	171,681	227,055	65,408	126,891	192,299	148,097		44,202
2006	2,436,039	616,197	1,375,068	169,114	227,332	48,328	124,324	172,652	128,476		44,176
REPAYMENT PERIOD											
2007	2,436,039	616,197	1,391,567	169,114	227,308	31,853	124,324	156,177	106,709	2,929	46,539
2008	2,436,039	616,197	1,403,951	169,114	220,240	26,537	124,324	150,861	104,301	21	46,539
2009	2,436,039	616,197	1,386,429	169,114	214,147	50,152	124,324	174,476	120,228	7,709	46,539
2010	2,436,039	616,197	1,384,646	169,114	209,070	57,012	124,324	181,336	134,797		46,539
2011	2,436,039	616,197	1,404,220	169,114	203,887	42,621	124,324	166,945	120,406		46,539
2012	2,436,039	616,197	1,426,419	169,114	205,245	19,064	124,324	143,388	96,038	811	46,539
2013	2,436,039	616,197	1,183,701	169,114	196,798	270,229	124,324	394,553	298,218	49,796	46,539
2014	2,436,039	616,197	1,178,246	169,114	184,453	288,029	124,324	412,353	317,260	48,554	46,539
2015	2,436,039	616,197	1,174,191	169,114	170,062	306,475	124,324	430,799	330,159	54,101	46,539
2016	2,436,039	616,197	1,164,287	169,114	155,360	331,081	124,324	455,405	344,602	64,264	46,539
2017	2,436,039	616,197	1,087,960	169,114	137,840	424,928	124,324	549,252	440,467	62,246	46,539
2018	2,436,039	616,197	926,143	169,114	116,779	607,806	124,324	732,130	660,131	25,460	46,539
2019	2,436,039	616,197	1,151,907	169,114	90,073	408,748	124,324	533,072	419,532	67,001	46,539
2020	2,436,039	616,197	1,151,912	169,114	74,180	424,636	124,324	548,960	465,678	36,743	46,539
2021	2,436,039	616,197	1,148,973	169,114	40,871	460,884	124,324	585,208	521,843	16,826	46,539
2022	2,436,039	616,197	1,149,472	169,114	11,874	489,382	124,324	613,706	551,336	15,831	46,539
2023	2,436,039	616,197	1,149,695	169,114	(12,099)	513,132	124,324	637,456	581,254	9,663	46,539
2024	2,436,039	616,197	1,136,230	169,114	(44,252)	558,750	124,324	683,074	615,463	21,072	46,539
2025	2,436,039	616,197	1,135,338	169,114	(74,498)	589,888	124,324	714,212	649,385	18,288	46,539
2026	2,436,039	616,197	1,134,782	169,114	(103,897)	619,843	124,324	744,167	678,752	18,876	46,539

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 (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)
2027	2,436,039	616,197	1,134,782	169,114	(133,835)	649,781	124,324	774,105	307,945	232,947	233,213
2028	2,436,039	616,197	1,134,782	169,114	(138,770)	654,716	124,324	779,040	222,776		556,264
2029	2,436,039	616,197	1,134,782	169,114	(140,051)	655,997	124,324	780,321	182,529		597,792
2030	2,436,039	616,197	1,133,782	169,114	(144,304)	661,250	124,324	785,574	37,938		747,636
2031	2,436,039	616,197	1,133,782	169,114	(141,174)	658,120	124,324	782,444	150,359		632,085
2032	2,436,039	616,197	1,133,782	169,114	(141,405)	658,351	124,324	782,675	140,461		642,214
2033	2,436,039	616,197	1,133,782	169,114	(143,546)	660,492	124,324	784,816	62,747		722,069
2034	2,436,039	616,197	1,133,782	169,114	(144,167)	661,113	124,324	785,437	42,345		743,092
2035	2,436,039	616,197	1,133,782	169,114	(139,934)	656,880	124,324	781,204	189,603		591,601
2036	2,436,039	616,197	1,133,782	169,114	(143,283)	660,229	124,324	784,553	76,768		707,785
2037	2,436,039	616,197	1,133,782	169,114	(141,847)	658,793	124,324	783,117	120,905		662,212
2038	2,436,039	616,197	1,133,782	169,114	(145,005)	661,951	124,324	786,275	13,508		772,767
2039	2,436,039	616,197	1,133,782	169,114	(140,898)	657,844	124,324	782,168	157,084		625,084
2040	2,436,039	616,197	1,133,782	169,114	(145,376)	662,322	124,324	786,646	639		668,350
2041	2,436,039	616,197	1,133,782	169,114	(142,050)	658,996	124,324	783,320	118,296		724,768
2042	2,436,039	616,197	1,133,782	169,114	(143,734)	660,680	124,324	785,004	58,552		726,452
2043	2,436,039	616,197	1,133,782	169,114	(143,782)	660,728	124,324	785,052	54,742		730,310
2044	2,436,039	616,197	1,133,782	169,114	(143,428)	660,374	124,324	784,698	68,740		715,958
2045	2,436,039	616,197	1,133,782	169,114	(141,992)	658,938	124,324	783,262	119,819		663,443
2046	2,436,039	616,197	1,133,782	169,114	(137,395)	654,341	124,324	778,665	280,543		498,122
2047	2,436,039	616,197	1,133,782	169,114	(138,202)	655,148	124,324	779,472	243,904		535,568
2048	2,436,039	616,197	1,133,782	169,114	(139,526)	656,472	124,324	780,796	197,781		583,015
2049	2,436,039	616,197	1,133,782	169,114	(143,696)	660,642	124,324	784,966	58,206		726,760
2050	2,436,039	616,197	1,133,782	169,114	(142,994)	659,940	124,324	784,264	82,164		702,100
2051	2,436,039	616,197	1,133,782	169,114	(140,991)	657,937	124,324	782,261	156,524		625,737
2052	2,436,039	616,197	1,133,782	169,114	(139,868)	656,814	124,324	781,138	188,205		592,933
2053	2,436,039	616,197	1,133,782	169,114	(139,418)	656,364	124,324	780,688	206,728		573,960
2054	2,436,039	616,197	1,133,782	169,114	(145,219)	662,165	124,324	786,489	6,111		780,378
2055	2,436,039	616,197	799,155	169,114	(152,289)	1,003,862	124,324	1,128,186	157,679		970,507
2056	2,436,039	616,197	799,155	169,114	(153,974)	1,005,547	124,324	1,129,871	101,320		1,028,551
GENERATION TOTALS	166,944,282	37,724,385	91,111,772	10,914,649	3,896,719	23,296,758	8,713,474	31,995,232	11,473,841	795,580	18,322,940

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

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

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

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

TABLE 8A
GENERATION REVISED REVENUE TEST
INCOME STATEMENT
($thousands)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	REVENUES FROM PROPOSED RATES	2,482,418	2,498,185	2,452,144	2,476,673	2,491,853
2	OPERATING EXPENSES:					
3	OPERATION & MAINTENANCE	466,468	450,818	444,424	439,716	437,458
4	PURCHASE AND EXCHANGE POWER-					
5	SHORT-TERM POWER PURCHASES 1/	507,113	513,714	474,771	510,830	502,206
6	LONG-TERM POWER PURCHASES	65,904	66,159	66,450	66,977	67,414
7	TROJAN	19,547	14,154	12,564	12,589	12,609
8	WNP NO. 1	178,104	168,240	175,007	168,294	180,376
9	WNP NO. 2	351,536	408,804	404,348	361,649	391,800
10	WNP NO. 3	156,806	156,162	152,401	152,649	151,006
11	RESIDENTIAL EXCHANGE - IOU SETTLEMENT	69,658	69,658	69,658	69,658	69,658
12	FISH & WILDLIFE	131,700	138,000	140,100	142,900	144,400
13	AMORTIZATION OF FISH & WILDLIFE	19,772	21,842	23,737	25,394	26,407
14	CONSERVATION	34,929	33,340	33,640	34,040	34,340
15	AMORTIZATION OF CONSERVATION	59,337	55,586	47,125	43,179	37,650
16	FEDERAL PROJECTS DEPRECIATION	97,608	100,773	103,661	106,003	108,403
17	TOTAL OPERATING EXPENSES	2,158,480	2,197,249	2,147,886	2,133,878	2,163,726
18	INTEREST EXPENSE:					
19	INTEREST ON FEDERAL INVESTMENT-					
20	ON APPROPRIATED FUNDS	252,003	255,597	261,715	267,926	268,119
21	ON LONG-TERM DEBT	63,472	67,412	72,664	77,374	80,178
22	INTEREST CREDIT ON CASH RESERVES	(59,720)	(66,354)	(72,126)	(76,868)	(81,499)
23	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
24	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(2,992)	(2,890)	(2,050)	(2,056)	(2,044)
25	NET INTEREST EXPENSE	205,025	206,237	212,328	221,586	219,964
26	TOTAL EXPENSES	2,363,505	2,403,486	2,360,214	2,355,464	2,383,690
27	NET REVENUES	118,913	94,699	91,930	121,209	108,163

1/	System Augmentation	432,988	447,536	399,929	434,514	416,840
	Balancing Power Purchases	74,125	66,178	74,842	76,316	85,366

TABLE 8B
GENERATION REVISED REVENUE TEST
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2002	B FY 2003	C FY 2004	D FY 2005	E FY 2006
1	CASH FROM CURRENT OPERATIONS:					
2	NET REVENUES	118,913	94,699	91,930	121,209	108,163
3	EXPENSES NOT REQUIRING CASH:					
4	FEDERAL PROJECTS DEPRECIATION	97,608	100,773	103,661	106,003	108,403
5	AMORTIZATION OF CONSERVATION/F&W INVESTMENT	79,109	77,428	70,862	68,573	64,057
6	CAPITALIZATION ADJUSTMENT	(47,738)	(47,528)	(47,875)	(44,790)	(44,790)
7	CASH PROVIDED BY CURRENT OPERATIONS	247,892	225,372	218,578	250,995	235,834
8	CASH USED FOR CAPITAL INVESTMENTS:					
9	INVESTMENT IN:					
10	UTILITY PLANT	(228,000)	(168,700)	(297,500)	(185,525)	(220,225)
11	CONSERVATION	0	0	0	0	0
12	FISH & WILDLIFE	(34,732)	(38,317)	(35,825)	(33,988)	(34,182)
13	CASH USED FOR CAPITAL INVESTMENTS	(262,732)	(207,017)	(333,325)	(219,513)	(254,407)
14	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:					
15	INCREASE IN LONG-TERM DEBT	127,032	125,917	98,425	97,013	97,207
16	REPAYMENT OF LONG-TERM DEBT	(66,000)	(25,622)	(27,400)	(30,757)	0
17	INCREASE IN CONGRESSIONAL CAPITAL APPROPRIATIONS	135,700	81,100	234,900	122,500	157,200
18	REPAYMENT OF CAPITAL APPROPRIATIONS	(41,401)	(47,362)	(64,885)	(117,340)	(128,476)
19	PAYMENT OF IRRIGATION ASSISTANCE	0	0	(739)	0	0
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	155,331	134,033	240,301	71,416	125,931
21	ANNUAL INCREASE (DECREASE) IN CASH	140,491	152,388	125,554	102,898	107,358

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 (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 **2/**		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 **3/**		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	2,686,700	319,400	1,938,000	136,000	216,600	76,700	136,000	212,700	196,544		16,156
1996	2,744,510	383,699	1,942,515	151,122	208,509	58,665	151,122	194,787 **/4**	135,010		59,777
1997	1,996,439	612,961	924,789	148,215	197,238	113,236	104,632	217,868	80,200	25,143	112,525
1998	2,060,750	665,005	1,091,678	162,562	201,930	(60,425)	118,440	58,015	61,000		(2,985)
1999	2,366,423	702,717	1,196,308	162,008	182,079	123,311	117,886	241,197	25,000		216,197
COST EVALUATION PERIOD											
2000	2,249,174	744,261	1,037,166	164,030	179,390	124,327	116,275	240,602	90,431		150,171
2001	2,181,778	711,185	1,014,519	169,530	203,938	82,606	121,538	204,144	53,787	16,560	133,797
RATE APPROVAL PERIOD											
2002	2,482,418	633,096	1,348,667	176,717	205,025	118,913	128,979	247,892	107,401		140,491
2003	2,498,185	622,157	1,396,891	178,201	206,237	94,699	130,673	225,372	72,984		152,388
2004	2,452,144	618,163	1,355,200	174,523	212,328	91,930	126,648	218,578	92,285	739	125,554
2005	2,476,673	616,656	1,342,646	174,576	221,586	121,209	129,786	250,995	148,097		102,898
2006	2,491,853	616,197	1,375,068	172,460	219,964	108,163	127,670	235,834	128,476		107,358
REPAYMENT PERIOD											
2007	2,491,853	616,197	1,391,567	172,460	219,940	91,688	127,670	219,359	106,709	2,929	109,721
2008	2,491,853	616,197	1,403,951	172,460	212,872	86,372	127,670	214,043	104,301	21	109,721
2009	2,491,853	616,197	1,386,429	172,460	206,779	109,987	127,670	237,658	120,228	7,709	109,721
2010	2,491,853	616,197	1,384,646	172,460	201,702	116,847	127,670	244,518	134,797		109,721
2011	2,491,853	616,197	1,404,220	172,460	196,519	102,456	127,670	230,127	120,406		109,721
2012	2,491,853	616,197	1,426,419	172,460	197,877	78,899	127,670	206,570	96,038	811	109,721
2013	2,491,853	616,197	1,183,701	172,460	189,430	330,064	127,670	457,735	298,218	49,796	109,721
2014	2,491,853	616,197	1,178,246	172,460	177,085	347,864	127,670	475,535	317,260	48,554	109,721
2015	2,491,853	616,197	1,174,191	172,460	162,694	366,310	127,670	493,981	330,159	54,101	109,721
2016	2,491,853	616,197	1,164,287	172,460	147,992	390,916	127,670	518,587	344,602	64,264	109,721
2017	2,491,853	616,197	1,087,960	172,460	130,472	484,763	127,670	612,434	440,467	62,246	109,721
2018	2,491,853	616,197	926,143	172,460	109,411	667,641	127,670	795,312	660,131	25,460	109,721
2019	2,491,853	616,197	1,151,907	172,460	82,705	468,583	127,670	596,254	419,532	67,001	109,721
2020	2,491,853	616,197	1,151,912	172,460	66,812	484,471	127,670	612,142	465,678	36,743	109,721
2021	2,491,853	616,197	1,148,973	172,460	33,503	520,719	127,670	648,390	521,843	16,826	109,721
2022	2,491,853	616,197	1,149,472	172,460	4,506	549,217	127,670	676,888	551,336	15,831	109,721
2023	2,491,853	616,197	1,149,695	172,460	(19,467)	572,967	127,670	700,638	581,254	9,663	109,721
2024	2,491,853	616,197	1,136,230	172,460	(51,620)	618,585	127,670	746,256	615,463	21,072	109,721
2025	2,491,853	616,197	1,135,338	172,460	(81,866)	649,723	127,670	777,394	649,385	18,288	109,721
2026	2,491,853	616,197	1,134,782	172,460	(111,265)	679,678	127,670	807,349	678,752	18,876	109,721

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 (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)
2027	2,491,853	616,197	1,134,782	172,460	(141,203)	709,616	127,670	837,287	307,945	232,947	296,395
2028	2,491,853	616,197	1,134,782	172,460	(146,138)	714,551	127,670	842,222	222,776		619,446
2029	2,491,853	616,197	1,134,782	172,460	(147,419)	715,832	127,670	843,503	182,529		660,974
2030	2,491,853	616,197	1,133,782	172,460	(151,672)	721,085	127,670	848,756	37,938		810,818
2031	2,491,853	616,197	1,133,782	172,460	(148,542)	717,955	127,670	845,626	150,359		695,267
2032	2,491,853	616,197	1,133,782	172,460	(148,773)	718,186	127,670	845,857	140,461		705,396
2033	2,491,853	616,197	1,133,782	172,460	(150,914)	720,327	127,670	847,998	62,747		785,251
2034	2,491,853	616,197	1,133,782	172,460	(151,535)	720,948	127,670	848,619	42,345		806,274
2035	2,491,853	616,197	1,133,782	172,460	(147,302)	716,715	127,670	844,386	189,603		654,783
2036	2,491,853	616,197	1,133,782	172,460	(150,651)	720,064	127,670	847,735	76,768		770,967
2037	2,491,853	616,197	1,133,782	172,460	(149,215)	718,628	127,670	846,299	120,905		725,394
2038	2,491,853	616,197	1,133,782	172,460	(152,373)	721,786	127,670	849,457	13,508		835,949
2039	2,491,853	616,197	1,133,782	172,460	(148,266)	717,679	127,670	845,350	157,084		688,266
2040	2,491,853	616,197	1,133,782	172,460	(152,744)	722,157	127,670	849,828	639		731,532
2041	2,491,853	616,197	1,133,782	172,460	(149,418)	718,831	127,670	846,502	118,296		787,950
2042	2,491,853	616,197	1,133,782	172,460	(151,102)	720,515	127,670	848,186	58,552		789,634
2043	2,491,853	616,197	1,133,782	172,460	(151,150)	720,563	127,670	848,234	54,742		793,492
2044	2,491,853	616,197	1,133,782	172,460	(150,796)	720,209	127,670	847,880	68,740		779,140
2045	2,491,853	616,197	1,133,782	172,460	(149,360)	718,773	127,670	846,444	119,819		726,625
2046	2,491,853	616,197	1,133,782	172,460	(144,763)	714,176	127,670	841,847	280,543		561,304
2047	2,491,853	616,197	1,133,782	172,460	(145,570)	714,983	127,670	842,654	243,904		598,750
2048	2,491,853	616,197	1,133,782	172,460	(146,894)	716,307	127,670	843,978	197,781		646,197
2049	2,491,853	616,197	1,133,782	172,460	(151,064)	720,477	127,670	848,148	58,206		789,942
2050	2,491,853	616,197	1,133,782	172,460	(150,362)	719,775	127,670	847,446	82,164		765,282
2051	2,491,853	616,197	1,133,782	172,460	(148,359)	717,772	127,670	845,443	156,524		688,919
2052	2,491,853	616,197	1,133,782	172,460	(147,236)	716,649	127,670	844,320	188,205		656,115
2053	2,491,853	616,197	1,133,782	172,460	(146,786)	716,199	127,670	843,870	206,728		637,142
2054	2,491,853	616,197	1,133,782	172,460	(152,587)	722,000	127,670	849,671	6,111		843,560
2055	2,491,853	616,197	799,155	172,460	(159,657)	1,063,697	127,670	1,191,368	157,679		1,033,689
2056	2,491,853	616,197	799,155	172,460	(161,342)	1,065,382	127,670	1,193,053	101,320		1,091,733
GENERATION TOTALS	169,726,351	37,724,385	91,111,772	11,077,459	3,541,872	26,270,864	8,876,284	35,132,148	11,473,841	795,580	21,459,856

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

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

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

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

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 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, Stat. 132.

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:

> *. . . at 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].*

Recently enacted section 7(n) of the Northwest Power Act provides additional guidance regarding cost recovery for the FY 2002-2006 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.*

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. 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-02-FS-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 Colvilles' claims for a portion of the revenues from Grand Coulee Dam, and directs the BPA to carry out its obligations under the settlement agreement.

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 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 2002-2006 rate period are $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 2002-2006 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. §8381, 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 §8381(b)(I). The Refinancing Act also specified that the new principal amounts of the old capital investments be assigned new interest rates from the Treasury yield curve prevailing at the time of the refinancing transaction. *Id*. at §8381(a)(6)(A).

The Refinancing Act restricts prepayment of the new principal to $100 million during the first five years after the effective date of the financing. 6 U.S.C. §8381(e). The Refinancing Act also specifies that repayment periods on new principal amounts may not be earlier than determined prior to the refinancing. *Id*. at §8381(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. 16 U.S.C. §8381(f) New capital investments are defined as capital investments funded by appropriations for a project placed in service after September 30, 1996. *Id*. at §8381(a)(3). The IDC in each FY of construction for new capital investments is the prevailing one year Treasury rate. *Id*. at §8381(f)(1). The IDC is capitalized and included in the principle. After the plant is completed, the principal amount is assigned an interest rate based on the Treasury yield curve prevailing in the year in which the plant is placed in service. *Id.* at §8381(g).

The 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. §8381(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. 16 U.S.C. §8381(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 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. §832(f), 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:

> *the [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.*

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.

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 nonpower portion of these fish and wildlife costs. Such nonpower 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 nonpower 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 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 nonpower 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 Revenue Requirement Study; Volume 1, Chapter 12 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A; Chapter 5.2.3.3 of the Wholesale Power Rate Development Study, WP-02-FS-BPA-05; and the Risk Analysis Study, WP-02-FS-BPA-03, and Risk Analysis Study Documentation, WP-02-FS-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 15-year history of conducting separate repayment studies for the transmission and generation functions, which has enabled BPA to transition to a bifurcated ratesetting 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, the Revenue Requirement Study incorporates only the separate repayment study for the generation function of the FCRPS for FY 2002-2006.

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 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, 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 5.1.5 of the Revenue Requirement Study, WP-02-FS-BPA-02.

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.

APPENDIX A

FCRPS COST REVIEW IMPLEMENTATION

Documents included:

Fact Sheet No. 7 – Close out on Cost Review (October 1998)

Fact Sheet No. 8 – Cost Review Implementation Plan (October 1998)

Cost Review Management Committee Recommendations (March 1998)
(Note: full discussion of the recommendations and explanatory information on the cost baselines are not included. An electronic copy of the full report and all supplemental documents can be seen and/or downloaded from BPA's website, http://www.bpa.gov. A hard copy can be obtained by calling BPA's Public Information Center at 1-800-622-4519).

Updates to Forecast of Generation Expenses (August 1999)

Crosswalk From 1996 Rate Case Revenue Requirement to Initial Proposal for FY 2002-2006 (August 1999)

Crosswalk From Cost Review Baseline to Issues '98 Expense Forecast (August, 1999)

Changes in Generation Expense Forecasts Since Issues '98 (August 1999)

Fact Sheet #7

BPA Targets Cost Savings

Close-out on Cost Review Recommendations

BPA is commiting to achieve savings equivalent to the total recommended earlier this year by a special Cost Review panel convened by the Northwest governors. How BPA will implement the recommendations is detailed in a separate document called the Cost Management Implementation Plan. It is available on request by calling the number at the end of this document or by visiting BPA's Web site at http://www.bpa.gov.

Although BPA is targeting the full annual power expense savings of $131 million for the 2002-2006 period, the Cost Review recommendations present significant challenges for BPA and for its major power suppliers, the U.S. Army Corps of Engineers, Bureau of Reclamation and Washington Public Power Supply System. Many of the panel's recommendations are "stretch goals" that involve costs over which BPA has limited influence. At least one of the recommendations will require new administrative flexibility through legislation. Recognizing these challenges, BPA is committed to aggressively managing its costs and to working with its partners to achieve the full savings.

Background on Cost Review

At the request of the region's governors in July 1997, BPA and the Northwest Power Planning Council sponsored a Cost Review panel that included BPA and council representatives and five "outside" experts. These experts had extensive experience in downsizing large organizations and managing costs in competitive environments. The panel examined BPA's cost structure and cost management strategies and developed specific recommendations to further reduce the costs that BPA will set rates to recover.

The Cost Review covered operation, maintenance and capital investment costs of the Federal Columbia River Power System, including transmission, for fiscal years 2002-2006 — the initial period for new power sales contracts. These include not only the costs that BPA incurs but generation costs of the Corps of Engineers, Bureau of Reclamation and the Washington Public Power Supply System. Fish and wildlife costs were not included in the review because they were being addressed in a separate regional process.

Thank you for participating in Issues '98. This public process was designed to give you an overview of and a context for major policy issues surrounding BPA's future. Your input will help BPA develop planning assumptions for our power and transmission rate cases. With the exception of cost-cutting recommendations, Issues '98 is not a decision-making process by BPA. Instead, your comments will help inform decisions made in other forums, both within the region and by Congress. This fact sheet focuses on what we heard and what we plan to do next. To learn more about how to participate in the various forums surrounding BPA's future, call (800) 622-4519.

BONNEVILLE POWER ADMINISTRATION

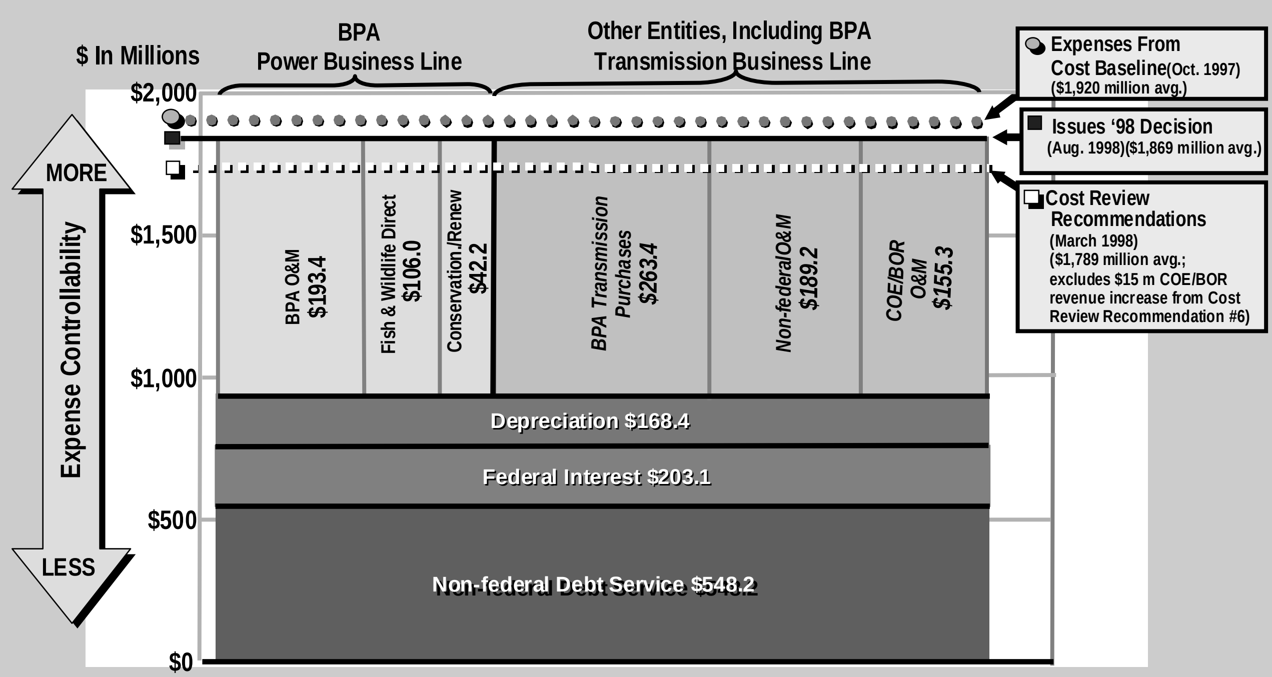
The objective of the Cost Review was to ensure that BPA's near- and long-term power and transmission costs are as low as possible, consistent with sound business practices. This will help ensure BPA can achieve full cost recovery with power rates at or below market levels. Accomplishing this would:

- Give BPA customers and constituents confidence that Federal Columbia River Power System costs are being managed effectively;
- Ensure that the Subscription process — for selling BPA power — results in a high level of customer commitment to BPA;
- Minimize, if not avoid entirely, transition (stranded) costs; and
- Ensure obligations to the U.S. Treasury, third-party bondholders, and fish and wildlife recovery remain at least as secure as they are currently.

Coming Up with Recommendations

In January 1998, the Cost Review panel released a set of draft recommendations that advocated additional cuts to the costs that BPA and other agencies of the Federal Columbia River Power System had planned for the 2002-2006 horizon. In March, following a public comment period, the panel submitted 13 final but advisory recommendations to the BPA administrator for consideration and action. The recommendations called for a combination of reduced federal power expenses ($131 million) from BPA's October 1997 spending forecast and increased revenue through asset management efficiencies ($15 million) in fiscal years 2002-2006 that together should produce annual savings averaging $146 million per year. If fully achieved, this would result in savings averaging $232 million a year from spending estimates in current rates (1997-2001).

FCRPS Power Expense Projections
FY 2002-2006 Averages



- BPA proposes to adopt the Cost Review recommendations, obtaining $125 million in cost reductions from power cost baseline
  - Savings from legislation to improve administrative efficiency/effectiveness not included above (pending development and support for legislation)
- Changes outside Cost Review recommendations: General Transfer Agreements expenses added (+$28 million); treatment of PNCA interchange expenses and revenues modified (-$20 million) and forecast of interbusiness line expenses (BPA transmission purchases) updated (+$66 million).
- Some expenses will change in rates development process, e.g. in-lieu transaction costs for residential exchange, resolution of allocation/functionalization/interbusiness line transaction issues, and federal interest cost and earnings projections.
- In addition, power rate proposal will include a margin for risk management (planned net revenues).

In Issues '98, BPA took public comment on its proposal to accept the recommended savings. Eighty participants in Issues '98 commented on BPA's cost management plan and practices. In general, they called on BPA to demonstrate its sincerity in managing its costs by ensuring that the recommendations are implemented in full. Some commentors wanted to understand what kind of benchmarking or monitoring would be used to measure success, and others wanted assurance that BPA could meet the proposed savings.

Implementing the Cost Savings

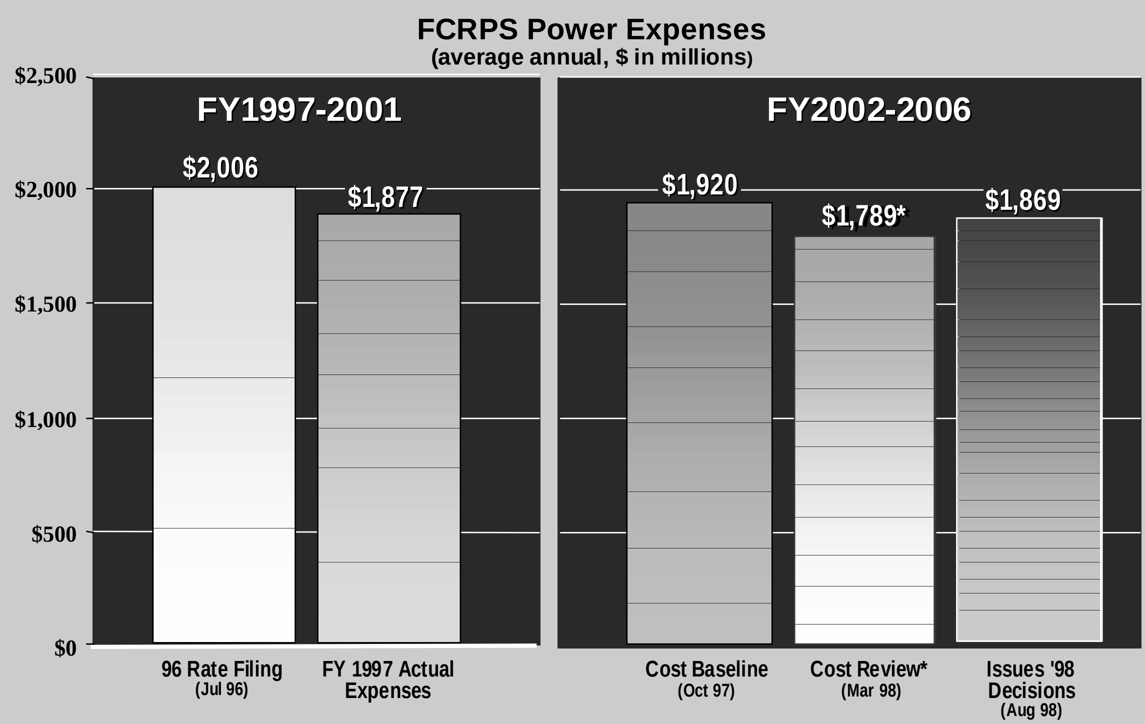
BPA is committed to aggressively managing its costs and to working with its partners to achieve the full total of Cost Review savings. BPA will be including the savings in its power rate proposal. The savings also will be reflected in budgets submitted to Congress and in internal cost management targets. To achieve an estimated $7 million in power savings, BPA must seek new statutory authority for personnel, procurement and property management to further improve efficiency and effectiveness.

BPA has already initiated aggressive changes in internal processes and systems. Although in terms of staffing BPA is at its smallest size since the mid-1960s, the four-year downsizing effort is being extended. Additional reductions in power, corporate and transmission functions are being planned. In addition, BPA will be working with its partners to implement an asset management strategy directed at maximizing the value of the Federal Columbia River Power System for the region.

In the upcoming power rate proceeding, BPA's revenue requirement will include cost components that are not covered in the Cost Review recommendations – in particular, short-term power purchase expense, net costs of the residential exchange, General Transfer Agreement costs, federal interest and depreciation, and

BPA is adopting the full total of the Cost Review recommendations

Issues '98 expenses for initial Subscription period are $137million lower than in current rates



*Excludes the $15 million in Corps of Engineers/Bureau of Reclamation revenue increases recommended by the Cost Review panel (recommendation #6).

- BPA entered Cost Review with an expense baseline for FYs 2002-2006 that was $86 million lower on the power side than expenses in current rates
- Cost Review recommended reducing this power baseline by an additional $131 million (with an additional $15 million in COE/BOR revenues)
- BPA plans to implement the Cost Review recommendations in a manner that would reduce the baseline by $125 million
- 2002-2006 changes to the power baseline outside the Cost Review include the cost of GTAs, as well as adjustments to interbusiness line and PNCA interchange expenses
- Some components of power expenses will change in rates development process this fall. Rates will also include a cash margin (planned net revenues) for risk management

interbusiness line expenses. In addition, BPA's rate proposal will include fish recovery costs and a risk analysis and management plan, including a planned net revenue component for risk. These cost components are subject to change as BPA develops its rate proposal and will be covered in workshops prior to the rate proceeding.

For More Information

In addition to this publication, the publications at the right are available upon request by calling BPA's Public Information Center at 1-800-622-4519. Copies also are available by visiting BPA's Web site at: http://www.bpa.gov. If you would like to speak to someone about any of these issues, please contact BPA using the number above or contact your BPA account executive.

ISSUES98 fact sheets

Fact Sheet #1
Cost Management

Fact Sheet #2
Future Fish and Wildlife Funding — Keeping the Options Open

Fact Sheet #3
Power Markets, Revenues, and Subscription

Fact Sheet #4
Transmission Issues

Fact Sheet #5
Risk Management

Fact Sheet #6
The Region Speaks: Summing Up Issues '98

Fact Sheet #7
BPA Targets Cost Savings: Close-out on Cost Review Recommendations

Fact Sheet #8
Cost Management Implementation Plan

Fact Sheet #9
Issues '98 Comment Analysis

Other documents available

BPA's Power Subscription Strategy Proposal

Issues '98 Comment Analysis

Fish and Wildlife Funding Principles

Bonneville Power Administration
P.O. Box 3621 Portland, Oregon 97208-3621
DOE/BP-3111 October 1998 3.5M

ISSUES98

Fact Sheet #8

Cost Review Implementation Plan

BPA is committed to aggressively managing its costs and to working with its partners to achieve the total effect of the Cost Review recomendations: $166 million per year in estimated cost reductions and revenue enhancements. BPA will be including the savings in its power rate proposal. The savings also will be reflected in budgets submitted to Congress and in internal cost management targets. To achieve an estimated $7 million of this effect, BPA must seek new statutory authority for personnel, procurement and property management to further improve efficiency and effectiveness.

BPA has already initiated aggressive changes in internal processes and systems. In terms of staffing, BPA is at its smallest size since the mid-1960s, but our four-year downsizing effort is being extended. Additional reductions in power, corporate and transmission functions are being planned. In addition, BPA will be working with its partners to implement an integrated asset management strategy directed at maximizing the value of the Federal Columbia River Power System for the region.

In the upcoming power rate proceeding, BPA's revenue requirement will include cost components that are not covered in the Cost Review recommendations – in particular, short-term power purchase expense, net costs of the residential exchange, General Transfer Agreement costs, federal interest and depreciation, and interbusiness-line expenses. In addition, BPA's rate proposal will include fish recovery costs and a risk analysis and management plan, including a planned net revenue component for risk These cost components are subject to change as BPA develops its rate proposal and will be covered in workshops prior to the rate proceeding.

Below are the summaries of the thirteen recommendations of the Cost Review and BPA's implementation plan for each recommendation. The full Cost Review recommendations are available upon request by calling BPA's Public Information Center at 1-800-622-4519. Copies are also available by visiting BPA's Website at: http://www.bpa.gov. If you would like to speak to someone about any of these issues, please contact BPA using the number above or contact your BPA account executive.

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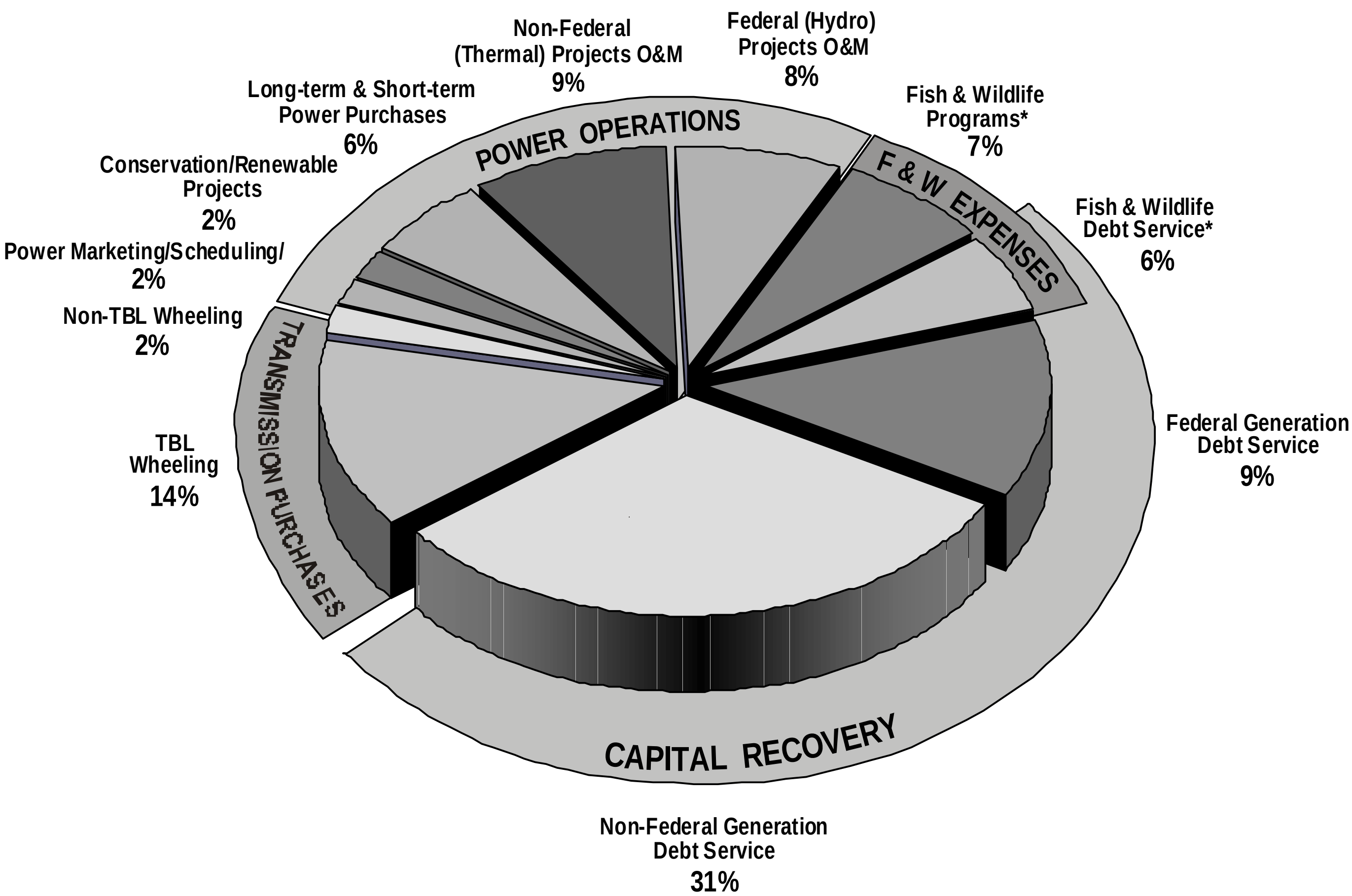
BONNEVILLE POWER ADMINISTRATION

Composition of Power Business Line Operating Expenses
FY 2002-2006 Average



Projected FY 02-06 Average Power Business Line Operating Expenses
($ in millions)

TBL Wheeling	$263.4	14%
Non-TBL Wheeling	$42.0	2%
Power Marketing/Scheduling	$33.4	2%
Conservation. Renewable Projects	$42.2	2%
Long-term & Short-term Power Purchases	$106.5	6%
Non-Federal (Thermal) Projects O&M	$164.3	9%
Federal (Hydro) Projects O&M	$154.2	8%
Fish & Wildlife Programs (see note below)	$123.5	7%
Fish & Wildlife Debt Service (see note below)	$119.9	6%
Federal Generation Debt Service	$251.6	13%
Non-Federal Generation Debt Service	$568.2	30%
Total PBL Expenses	$1,869.2	100%

** Note: The F&W funding amounts shown here reflect estimates developed for the Cost Review and Issues '98 and do not include operational costs (i.e., power purchases related to fish). Since then, BPA has proposed F&W principles for its power rate case and subscription process which commit BPA to a goal of achieving a high probability of repaying the Treasury taking into account a range of possible F&W funding requirements. This range is not shown here.*

Power Business Line Operating Expenses

($ in millions)	2002	2003	2004	2005	2006	02-06 ave.
1. CSRS Pension Expense	22.1	14.0	12.4	10.6	9.3	13.7
2. Power Marketing & Scheduling	40.4	32.0	24.4	20.1	21.2	27.6
3. Wheeling	42.0	42.0	42.0	42..0	42..0	42..0
4. *ST Purchased Power & Storage*	*80.56*	*87.2*	*75.5*	*72.9*	*77.5*	*78.7*
5. Generation Oversight	3.0	2.9	3.0	3.0	3.1	3.0
6. Conservation & Consumer Services	18.2	16.6	16.9	17.3	17.6	17.3
7. *Fish & Wildlife**	100.0	103.1	106.3	109.6	112.9	106.4
8. Corporate Expenses	7.7	6.6	6.7	6.7	6.7	6.9
9. Planning Council	5.1	5.1	5.1	5.1	5.1	5.1
10. *Corps of Engineers O & M*	108.0	85.0	85.0	84.0	84.0	89.2
11. U.S. Fish & Wildlife O & M	15.4	16.2	17.0	17.9	18.8	17.1
12. Bureau of Reclamation O & M	48.0	49.3	49.3	49.3	49.3	49.0
13. Colville Settlement	16.0	16.0	16.0	16.0	16.0	16.0
14. Renewable Projects	20.3	20.1	20.0	19.9	16.1	19.3
15. WNP-1 & WNP-3 Preservation Costs	3.5	3..6	3.6	3.6	3.6	3.6
16. WNP-2 & O & M Requirements	139.1	148.8	155.7	158.8	164.8	153.4
17. Trojan Decommissioning	9.6	4.2	2.6	2.6	2.6	4.3
18. Between Business Lines	261.5	262.4	265.1	263.9	264.2	263.4
19. LT Power Purchases	26.8	27.2	27.7	28.3	28.8	27.8
20. Undistributed Expense Reduction	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)	(20.0)
21. Non-Federal Projects Debt Service	557.6	594.6	586.2	534.0	568.6	568.2
22. Conservation Financing	5.6	5.6	5.6	5.6	5.6	5.6
23. *Federal Projects Depreciation*	173.1	172.7	167.2	166.2	162.6	168.4
24. *Net Residential Exchange*	0.2	0.2	0.2	0.2	0.2	0.2
25. *Net Federal Interest expense*	222.1	214.8	206.2	195.6	1767.6	203.1
26. Total	1,905.9	1,910.2	1,879.7	1,813.2	1,837.2	1,869.2

The italicized items denote cost categories that are subject to change as BPA completes its revenue requirement for the upcoming power rate case.

** Note: The F&W funding amounts shown here reflect estimates developed for the Cost Review and Issues '98 and do not include operational costs (i.e., power purchases related to fish). Since then, BPA has proposed F&W principles for its power rate case and subscription process which commit BPA to a goal of achieving a high probability of repaying the Treasury taking into account a range of possible F&W funding requirements. This range is not shown here.*

Description of Expenses - Power Business Line

Expenses	
1. CSR Pension Expense	Bonneville expects to cover the full unfunded liability of retirement benefits, pending a review of legal authority. The cost recovery will be phased in over a ten-year period, per agreement with the Administration.
2. Power Marketing & Scheduling	Primarily personnel costs, both federal and contractor FTE, for marketing and selling power and for operation of the Federal Columbia River Power System
3. Wheeling	Primarily General Transfer Agreements (GTA's) costs for wheeling electricity over BPA's customer-owned transmission facilities.
4. *ST Purchased Power & Storage*	Costs associated with the purchase of power from other entities/institutions.
5. Generation Oversight	Personnel costs for management of other entity generation projects such as WPPSS.
6. Conservation & Consumer Services	Primarily existing contract costs for conservation projects/programs.
7. *Fish & Wildlife*	Costs associated with the direct funding of Fish & Wildlife program activities, including personnel.
8. Corporate Expenses	Corporate overhead costs associated with building rents & maintenance, financial services, general services, computer support, security, human resources, etc.
9. Planning Council	Operational costs of the Pacific Northwest Planning Council.
10. *Corps of Engineers O&M*	Annual power generating operation and maintenance costs of the Corps of Engineers
11. U.S. Fish & Wildlife O&M	Annual operation and maintenance costs of the US F&W Lower Snake River Compensation Plan hatcheries program.
12. Bureau of Reclamation O&M	Annual power generating operation and maintenance costs of the Bureau of Reclamation
13. Colville Settlement	Annual payment to the Confederated Tribes of the Colville Reservation for their claims concerning their contribution to the production of hydropower by the Grand Coulee Dam (Settlement Agreement 4/94).
14. Renewable Projects	Wind and geothermal generation project costs.
15. WNP-1 & WNP-3 Preservation Cost	Site restoration costs for the terminated Washington Public Power Supply System nuclear plant.
16. WNP-2 O&M/Capital Requirements	O&M costs for WPPSS nuclear generating plant.
17. Trojan Decommissioning	Decommissioning costs for Trojan nuclear plant.
18. Between Business Line Expense	Primarily transmission costs purchased from the Transmission Business Line (BPA).
19. LT Power Purchases	Contract costs for the purchase of power from other entity generation projects (e.g., Idaho Falls, Cowlitz Falls, Wauna).
20. Undistributed Expense Reduction	Cost reductions identified as necessary but not yet specified.
21. Non-Federal Debt Service	Debt service
22. Conservation Financing	Debt service
23. *Depreciation*	Depreciation is the annual capital recovery expense associated with power plant in service (includes amortization of BPA's investments in energy conservation measures and fish and wildlife projects).
24. *Net Residential Exchange*	Costs associated with providing residential and small farm customers of investor-owned and publicly-owned utilities with the benefits of low-cost Federal power.
25. *Net Federal Interest Expense*	Interest on long-term debt includes interest on bonds that BPA issues to the U.S. Treasury and appropriations used to fund capital projects related to power net of interest and other credits.

The italicized items denote cost categories that are subject to change as BPA completes its revenue requirement for the upcoming power rate case.

Cost Review Recommendation #1:

Further reduce staffing and support costs of power marketing and other Power Business Line functions not directly related to operation of the federal power system.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$50.0 million/year
Cost Review Recommendation (Mar. 98):	$35.3 million/year
Cost Review Annual Savings:	$14.7 million/year
Issues '98 Decision (Aug. 98):	$14.7 million/year

Cost Review Recommendation:

Further reduce staffing and support costs of power marketing and other PBL functions not directly related to operation of the federal power system.

BPA Implementation Plan:

BPA is adopting the Cost Review recommendation for cost and staff reductions as its goal. BPA is pursuing this goal consistent with the broader strategy of managing the FCRPS to maximize its value for the region.

- Steps BPA is taking immediately to achieve this goal:
  - developing standardized power products and contracts to reduce staffing needed for contract administration in the future
  - focusing heavily on a successful subscription process at below market rates with the goal that BPA firm power be subscribed for multi-year periods to reduce the need for future marketing effort
  - investing in improved automated systems for power scheduling and billing
  - using staff from within PBL and other BPA organizations as much as possible when filling key vacancies
  - using early retirement and separation incentives to reduce staff

Challenges/Risks

By themselves, the steps described above may not be enough to achieve the target reductions. The Cost Review assumption was that BPA's cost-based rates would be far below market, making it possible to subscribe all of the system for periods of at least five years, and probably longer. This in turn was assumed to allow large reductions in staffing and support costs for contracting, rate-setting, account executives, customer service and similar functions. ·

- It is not yet clear how close BPA can come to the Cost Review vision of BPA rates far below market and full, long-term subscription. Many of the estimates of future fish mitigation cost scenarios for post-2001 are far higher than the level assumed in the Cost Review. The range of potential fish mitigation costs post-2006 is especially wide. BPA is working to define the range of fish costs it needs to plan to cover. Likewise, there is a wide range of expectations of market price levels after 2001.
- By mid-1999, several events will have occurred that should make more clear whether the Cost Review vision of rates significantly below market can be realized: post-2001 market price expectations will be clearer; the power rate case should be completed; and many customers will have responded to BPA's subscription offer. These events will help to clarify the necessary level of long-term marketing and customer service support. In the meantime, BPA will continue to take the above-described steps toward the Cost Review reductions and will treat the Cost Review recommendation for costs and staffing as its goal.
- Another challenge that has emerged since the Cost Review is increasing staffing demands created by the new California Power Exchange/Independent System Operator operation and the split between BPA's business lines. The new California market has created a substantially increased need for around-the-clock staffing in power scheduling, transmission acquisition and related functions for BPA and many other utilities and marketers on the West Coast. This increases the importance of creating automated systems to bring staffing levels for these core operations back down to Cost Review baseline levels. Nonetheless, these increased demands may result in higher numbers post-2001 in these functions than assumed in the Cost Review baseline staffing levels.

Customer Comments:

Will a reduction in staffing levels erode current improved relationships with customers?

Improved customer relations will continue to be a primary goal for BPA. BPA acknowledges that any significant staffing decrease to the Power Business Line will be across all operations including customer support. However, staffing decreases would follow such counterbalancing efforts as increasing standardization of products and a successful subscription process that decrease staffing need, not erode customer relations.

Fund regional conservation market transformation at a level proportional to the percent of the regional firm load served by BPA. Carry out a review of the need for, and the appropriateness of, continued Bonneville support beyond the 10-year life established in the Comprehensive Review.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$14.6 million/year
Cost Review Recommendation (Mar. 98):	$10.0 million/year
Cost Review Annual Savings:	$ 4.6 million/year
Issues '98 Decision (Aug. 98):	$ 4.6 million/year

Cost Review Recommendation:

Fund regional conservation market transformation at a level proportional to the percent of the regional firm load served by Bonneville, as called for in the Comprehensive Review. Reductions shown reflect correction to BPA's baseline funding. Work with retail utilities and states to secure funding for conservation market transformation through state public purpose funds, as recommended by the Comprehensive Review. By not later than 2004, carry out a review of the funding available for this activity from other sources and the appropriateness of continued BPA funding beyond the 10-year minimum life established in the Comprehensive Review.

BPA Implementation Plan:

Adopt recommendation. This recommendation is fully consistent with policy direction in the Comprehensive Review.

- The Cost Review figure of $10 million reflects an estimate of BPA's share of the regional firm load in 2002-2006. BPA loads may be a greater or lesser proportion of regional loads; therefore, actual expenditures for market transformation may be higher or lower than $10 million.
- BPA's collection of these costs in its rates will be competitively neutral, assuming that the states enact legislation that requires customer expenditures for market transformation and enables BPA customers to credit BPA funding towards their expenditure obligation.
- Work with retail utilities and the states to secure funding for conservation market transformation through state public purpose legislation, as recommended by the Comprehensive Review.
- BPA intends to act as an advocate and catalyst to encourage customers to opt for efficiency and renewable resources, helping them explore the value and benefits these have to offer. The subscription proposal contains an initial proposal for an incentive for BPA firm power purchasers to invest in these new conservation and renewable resources. In designing an incentive to encourage conservation and renewables, it's anticipated that support for utilities would be proportional to the amount of power purchased from BPA and that no involuntary income transfers would occur between BPA rate classes or utilities. BPA hopes this proposal will encourage state legislatures and regional power planning organizations to establish direction for the Pacific Northwest's development of conservation and renewable resources.
- By no later than 2004, review appropriateness of continued BPA support.

Customer Comments:

BPA, in the past and currently, has supported energy conservation. You've sold surplus power where it's available to sell. We've paid for it, but it's sold outside the region. Now we're going to have to pay again, with the benefit going outside. How can you achieve equity and be competitive? The cost to Washington might be different from that to Oregon. What are those out of the region going to pay?

Conservation produces benefits day in and day out. Participants always benefit from energy efficiency. The region's benefit is always there but will vary. When the region has a shortage of power, the amount we pay to buy power is reduced. When the region has excess energy or capacity to sell on the market, how much the region gains and how much the out-of-region purchasers pay for the available power will depend on the market value of the power. This can sometimes be substantial. The cost of market transformation will vary by state, depending on loads, but the benefits should also follow because the biggest markets are usually the highest load areas. BPA, through its work on the board of the Northwest Energy Efficiency Alliance, will encourage equity across states and customer classes.

States have not acted to replace BPA's decimated public purposes budgets as recommended by the Review.

BPA and the Cost Review Panel recognize that the commitments of the Comprehensive Regional Review will require constant emphasis in order to be fully implemented. Please see the fourth bullet of the Implementation Plan for further information on how BPA proposes to encourage state participation.

Stabilize market transformation through total participant contribution from all customer groups.

BPA recognizes that without a non-bypassable, competitively neutral distribution charge to fund public benefits as called for in the Comprehensive Review, there may be some utilities or customer groups who will not be contributing to regional market transformation efforts. This is unfortunate, as all will benefit from successful market transformation. The Cost Review Recommendation reiterates the intent of the Comprehensive Review that BPA should not be paying for those who aren't otherwise contributing.

Cost Review Recommendation #3:

Reduce projection of legacy conservation contract and staffing expenses. Allow Bonneville to extend low-income weatherization contracts with the states to be consistent with the end of the legacy contract commitments to the utilities.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$10.0 million/year
Cost Review Recommendation (Mar. 97):	$7.5 million/year
Cost Review Annual Savings:	$2.5 million/year
Issues '98 Decision (Aug. 98):	$2.5 million/year

Cost Review Recommendation:

Reduce projected legacy conservation contract expenses to reflect historical underspending. Do not modify or extend existing contracts, except that the states' low-income weatherization contracts should be extended consistent with the end of the legacy commitment to utilities. Reduce associated staffing.

BPA Implementation Plan:

Adopt recommendation.

- Conservation contractors typically underspend contract budgets. Savings estimates reflect historical underspending trends, however, there remains significant uncertainty on actual utility spending.
- Low-income weatherization agreements with the states will be extended, consistent with the Cost Review recommendation.
- Revised estimates reflect a reduction in associated staffing for this activity.

Customer Comments:

Conservation is still a role BPA needs to play until someone else funds it. BPA should support cost-effective and innovative conservation efforts like the Northwest Energy Alliance and continue follow-through on renewable resource commitments.

BPA will continue to support the Northwest Energy Efficiency Alliance consistent with the Comprehensive Review and the recommendations of the Cost Review. BPA is following through on its commitments to the development of renewable resources.

Cost Review Recommendation #4:

Further reduce staffing/funding for the Northwest Power Planning Council.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$6.2 million/year
Cost Review Recommendation (Mar. 98):	$5.1 million/year
Cost Review Annual Savings:	$1.1 million/year
Issues '98 Decision (Aug. 98):	$1.1 million/year

Cost Review Recommendation:

Further reduce funding for the Council to reflect changes in BPA's regional role, i.e., very limited new resource acquisition while carying out the Council's role in power as recommended by the Comprehensive Review and reflecting the continued importance of fish and wildlife issues. Seek additional funding from other sources for Council activities that are of regional scope. Reductions assume one Council representative per state. A process should be carried out to determine both the functions the region wishes the Council to perform and how the functions should be funded.

BPA Implementation Plan:

Adopt recommendation.

- The reductions may put the Council's capacity to perform independent analysis for the region at risk.
- Once a future role is clarified for the Council, BPA will work with the Council to look for other funding sources for activities that are of regional scope.

Customer Comments:

Will the reduction in funding impose limitations on the Council's ability to make crucial decisions?

The reduction in funding may diminish the Council's ability to perform regional analysis and other tasks. However, after the Council's role has been more clearly defined, BPA will work with the Council to identify other financial resources to support key regional activities.

Cost Review Recommendation #5:

Renewable resource projects: new projects beyond those currently committed must be supported by incremental revenues that cover the additional costs.

	(FY2002-06 Annual Average)
BPA Cost Baseline (May 97):	$24.9 million/year expense
Cost Review Recommendation (Mar. 98):	$22.7 million/year expense
Cost Review Annual Savings:	$2.2 million/year
Issues '98 Decision (Aug. 98):	$2.2 million/year

Cost Review Recommendation:

Provide funding for costs of the three renewable resource projects that BPA currently is planning, and provide currently planned levels of renewable resource data collection and research and development. Annual net cost above project revenues should not exceed $15 million per year, including the data collection and research and development costs. No additional renewable resource projects should be undertaken unless Bonneville's costs are recovered fully by project revenue.

BPA Implementation Plan:

Adopt recommendation.

- BPA is proceeding with development activities on three renewable projects (two geothermal and one wind) that could result in a decision to proceed with construction on two of the projects. These would be in addition to the Wyoming wind project currently under construction.
- We will attempt to hold costs for project development, operation and data collection for these projects to less than $22.7 million per year to ensure the net cost does not exceed $15 million per year.
- We will also continue to market the output from the projects at green power rates, which will maximize cost recovery.
- Additional renewable projects will be acquired only if costs are fully recovered by resulting revenues.

Risks/Challenges

Project costs could be higher than anticipated and actual revenues could be lower or higher than assumed depending on the market.

- BPA might not be viewed as a desirable power supplier by target customers if it cannot meet their demand for new renewables, particularly if the market transformation activities recommended by the Comprehensive Review are implemented.
- The Cost Review rationale is that BPA's core business strategy should not include the development of additional renewable resources or additional related research unless project costs are fully recoverable by project revenues. This may be interpreted by some to be contrary to the Northwest Power Act purposes, which charge BPA broadly with encouraging renewable resource development.

Customer Comment:

We want BPA to ensure that the system is as efficient as it can be and that it becomes cleaner over time.

Please encourage customers to continue renewables development.

Will BPA commit resources to research and development of new technologies in renewable energy and energy conservation?

BPA will continue its support of renewable resource development as mandated by the Regional Act while complying with the cost constraints recommended by the Cost Review.

BPA remains committed to the Cost Review recommendations, specifically the recommendation that BPA fund three renewable resource projects and provide currently planned levels of renewable resource data collection and R&D. While the Cost Review limits BPA's role in expanding the renewables market, our sanctioned development efforts on three renewable projects, combined with the development efforts of other PNW utilities should 1) provide encouragement to developers, 2) provide enough product to supply the market, and 3) stimulate more demand.

BPA seeks to sell these renewable resources, both within and outside the region, at a premium price as "green" power. This marketing effort should allow BPA to respond to (and hopefully to stimulate) market demand for clean resources, to cover resource costs and to encourage others to develop clean green resources for the market. If the market demands it and there is customer support, BPA may seek to develop additional renewable projects, provided that the projects' costs are covered by project revenues.

As mentioned, BPA intends to act as an advocate and catalyst to encourage customers to opt for efficiency and renewable resources, helping them explore the value and benefits these have to offer. The subscription proposal contains an initial proposal for an incentive for BPA firm power purchasers to invest in these new conservation and renewable resources. In designing an incentive to encourage conservation and renewables, it's anticipated that support for utilities would be proportional to the amount of power purchased from BPA and that no involuntary income transfers would occur between BPA rate classes or utilities. BPA hopes this proposal will encourage state legislatures and regional power planning organizations to establish direction for the Pacific Northwest's development of conservation and renewable resources.

Further, BPA has agreed to pay a portion of the market premium realized from the sale of green power to the Bonneville Environmental Foundation to help maximize the development of renewables. The Foundation is not an agency nor an establishment of the United States and payments to the Foundation do not diminish BPA's obligation to fund the development of renewable resources. Foundation activities will complement BPA activities.

The Foundation is a charitable and nonprofit public benefit corporation dedicated to encouraging and funding projects that develop and/or apply clean, environmentally preferred, renewable power, as well as acquire, maintain, preserve, restore, protect, and/or sustain fish and wildlife habitat within the Pacific Northwest.

Cost Review Recommendation #6:

Develop/implement a consolidated/integrated capital/asset management strategy for the FCRPS, including transmission.

US Army Corps of Engineers

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$116.7 million/year – O&M
Cost Review Recommendation (Mar. 98):	$86.7 million/year – O&M
Cost Review Annual Savings:	$30.0 million/year – O&M
	$10.0 million/year – enhanced revenue
Issues '98 Decision (Aug. 98):	$30.0 million/year - O&M
	Revenue enhancement not estimated at this time.

Bureau of Reclamation

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$50.9 million/year – O&M
Cost Review Recommendation (Mar. 98):	$47.9 million/year – O&M
Cost Review Annual Savings:	$3.0 million – O&M·
	$5.0 million/year – Enhanced revenue
Issues '98 Decision (Aug. 98):	$3.0 million/year - O&M
	Revenue enhancement not estimated at this time.

Cost Review Recommendation:

Develop and implement a consolidated, integrated capital/asset management strategy for federal hydro directed at maximizing value, including both financial returns and public benefits. The strategy should encompass the operation and maintenance of the physical assets, a coordinated investment plan, potential consolidation of duplicate administrative support services among FCRPS agencies and the creation of integrated performance measures. Performance should be measured explicitly and reported publicly, accountabilities established and incentives created and applied FCRPS-wide. Estimates include a combination of reduced O&M expenses from the Cost Baseline and increased revenues from higher production.

BPA Implementation Plan:

Adopt the Committee's recommendation as BPA's goal, recognizing that the aggressive cost targets may pose risks to system performance.

- Savings recommendation would require that the Corps manage average annual O&M in FYs 2002-2006 to FY 1996 actual levels.
- BPA will work closely with the other members of the FCRPS to forge and integrate asset management plans directed at maximizing value for the region (financial returns and public benefit returns).
- These plans will further improve operations and maintenance cost management by benchmarking functions against best industry practices and establishing integrated performance measures and incentives to clarify and help ensure performance accountability.
- Potential consolidation of duplicate administrative services will be investigated to gain additional efficiencies.
- The asset management plans will include coordinated investment plans that rigorously analyze investment, disinvestment and divestiture opportunities directed at maximizing the value of the FCRPS.
- At this point, potential savings for the FY2002-2006 period average about $8 million per year for the Corps and $3.6 million per year for Reclamation. As the integrated asset management plans

are developed, additional efficiencies will be identified. These efforts will begin in FY 1999.

- From FY1990 to FY1996 FCRPS hydropower availability decreased from 92 percent to 82 percent, apparently due to underfunding of an aging system. Through collaborative efforts and direct funding arrangements between BPA, the Corps and Reclamation, FCRPS hydropower availability improved to 85 percent in FY1997. To meet the enhanced revenue goal, BPA, the Corps and Reclamation will continue to work collaboratively to increase project generation capability.
- The structure of the FCRPS is such that control over the quality and cost of production is largely separated from the responsibility for marketing and recovering costs. FCRPS entities operate with multiple and often competing purposes and objectives. This complicates forging an integrated asset management strategy. This recommendation requires long-term commitment, determination and creativity from FCRPS owners to maximize financial returns and public benefits for the region.
- Long lead times are involved with these improvements, and all savings may not be available by FY 2002.

Customer Comment:

We recommend BPA work to create "a more businesslike arrangement" with the Corps and Bureau.

BPA should maximize efficiencies in operations and maintenance.

BPA has been working with the Corps and Reclamation to create a closer and more businesslike relationship, and already has achieved some efficiencies as a result. The goal is to create efforts that more easily can be coordinated. While in the past, the structure of the FCRPS separated the responsibilities of quality and cost of production from that of marketing, BPA is committed to work with the Corps and Reclamation to develop an integrated asset management strategy in order to facilitate more businesslike investment and operation decisions.

BPA is attempting to maximize efficiencies in operations and maintenance. We have developed plans to improve operations and maintenance cost management in order to gain efficiencies. These plans include benchmarking of our management functions and operations against the best industry practices. These efforts will improve the operations and maintenance functions and enhance the value of the FCRPS by reducing costs while optimizing system production.

Cost Review Recommendation #7:

WNP-2: Aggressive cost management, flexible response to market conditions.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$172.5 million/year operating expenses
	$153.8 million/year operating revenues
	($18.7) million/year net operating revenues
Cost Review Recommendation (Mar. 98):	zero - net operating revenues
Cost Review Annual Savings:	$18.7 million/year - net operating revenues
Issues '98 Decision (Aug. 98):	$18.7 million/year - net operating revenues

Cost Review Recommendation:

Implement a strategy for Washington Public Power Supply System's nuclear plant, WNP-2, that combines aggressive cost management with a flexible response to market conditions and unforeseen costs. Manage annual operating costs to annual revenues achievable within market constraints. In BPA's subscription process and upcoming rate case, determine how to allocate the plant's costs in BPA rates so that its portion of the Federal Base System on a planning basis can be marketed to ensure full recovery of the plant's operating costs (unless legal or other issues prevent doing so). To the extent revenues can exceed operating costs, use a portion of the resulting net operating revenues to build up the decommissioning fund. Biennially subject the plant's operating costs to a market test. Evaluate termination in the event operating costs are projected to exceed operating revenues. Estimated savings include a combination of reduced O&M expense from the cost baseline and potential increased revenues.

BPA Implementation Plan:

BPA agrees with the basic objective of the Cost Review recommendation "to ensure that the operations of the plant not be insulated from the discipline of the marketplace" and to achieve the recommended increase in net operating revenues.

- BPA intends to subject WNP-2 operating costs to a market test biennially, testing whether market value of the WNP-2 output recovers annual operating costs of the plant. BPA intends to solicit input on the precise nature of this market test in a public process this year.
- Likewise, as recommended in the Review, BPA intends to re-evaluate plant termination if operating costs are projected to exceed revenues achievable at market prices by more than the termination costs.
- With the cost and revenue projections assumed by the Cost Review, this would require about $19 million of operating cost reductions and/or revenue increases. BPA will work with the Supply System to achieve as much of this enhancement of net revenues as possible through reductions in operating costs.
- BPA intends to work with the Supply System to achieve additional operating cost efficiencies, avoid major capital additions, shorten outages and, potentially, change from an annual to a biennial refueling cycle (would reduce from five to two the number of refuelings during the next five-year rate period).
- Cost reductions assume, in part, that there are no major equipment failures and no extensive additional regulation.
- The Cost Review also recommended that BPA market a portion of the FBS equivalent to the planned output of WNP-2 priced in a manner that ensures recovery of the plant's operating costs in the actual sales of the plant's output. Subject to further input, BPA's tentative conclusion is that the problems connected with this piece of the recommendation may not be practicably solvable given several issues that have emerged since the Cost Review: (1) the likelihood that BPA will have insufficient inventory to meet demands for firm

power in its subscription process; (2) additional complexity introduced by the present Fish Funding Agreement; and (3) certain specific aspects of BPA's subscription proposal. It would involve selling a portion of the Federal Base System at a higher price equal to WNP2's operating costs – a legal difficulty – and reduction of the lowest cost subscription inventory when it appears that we will be oversubscribed. WNP-2's operating costs are now so close to the market and to BPA's likely subscription power rates that the cost impact of this separation on both the subscription rate and the theoretical WNP-2 rate would be negligible. Equity concerns among parties with subscription rights over who is left with the higher-priced portion of power would likely exacerbate the oversubscription issues (see Power Markets, Revenues and Subscription Fact sheet). Finally, a robust market test should achieve the bulk of the Cost Review goal without creating the substantial problems connected with putting a higher price on this portion of the subscription inventory.

Customer Comment:

WNP-2 will never be cost effective, but BPA continues to insist on operating it.

Implement the Cost Review recommendation.

Political pressure forced the Cost Review panel to soften its WNP-2 recommendation; however, customers supported full implementation.

BPA has committed to subject WNP-2 operating costs to a market test. This biennial test will determine whether the market value of the WNP-2 output recovers annual operating costs of the plant. As recommended in the Cost Review, BPA will evaluate plant termination if operating costs are projected to exceed revenues achievable at market prices by more than the termination costs.

Cost Review Recommendation #8:

Reduce Administrative and Other Internal Support Service Costs.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$15.4 million/year - PBL portion of corporate overhead
Cost Review Recommendation (Mar. 98):	$6.9 million/year - PBL portion of corporate overhead
Cost Review Annual Savings:	$8.5 million/year - direct PBL savings
Issues '98 Decision (Aug. 98):	$8.6 million/year - direct PBL savings
	$5.9 million/year - indirect PBL savings from lower
BPA transmission costs	$14.5 million/year - total PBL savings

Cost Review Recommendation:

Further reduce the cost of BPA administrative and other internal support service costs, including financial, human resources, information management, procurement, strategic planning, public affairs, legal services and other internal service costs, by an aggregate 50 percent from 1996 actual levels. Achieve through redesign of shared services, benchmarking, adoption of industry "best practices," implementation of enterprise software and outsourcing of non-core functions where economic.

BPA Implementation Plan:

Adopt recommendation.

- Shared services redesign focuses on fundamental service activities across BPA, i.e., within each business line as well as within corporate.
- Savings from this effort will, therefore, lead to lower corporate costs and lower business line costs.
- Initial implementation of shared services redesign, including a reorganization of corporate shared services (the Business Services Group), is set for FY 1999. Full implementation will be completed by start of FY 2002. The precise breakdown of savings in corporate and the business lines will not be available until the redesign is complete.
- Also included in the cost savings here are reductions in administrative activities not a part of the shared services redesign effort, such as strategic planning, public affairs and legal services.
- Currently, BPA assumes the $31.7 million savings total will be applied as an average annual reduction to the FY 2002-2006 cost baselines and that the savings are achieved proportional to the distribution of corporate overheads to the business lines.
- BPA anticipates making a final decision on an enterprise software package in FY 1999, with implementation following immediately.

Customer Comment:

No comments received.

Cost Review Recommendation #9:

Obtain legislation to improve administrative effectiveness and efficiency.

	(FY2002-2006 Annual Averages)
Cost Review Recommendation (Mar. 98):	$7.0 million/year - PBL savings
Cost Review Annual Savings:	$7.0 million/year – PBL savings
Issues '98 Decision (Aug. 98):	not assumed

Cost Review Recommendation:

Obtain legislative changes in the areas of personnel management and procurement to improve administrative flexibility and ability to manage internal costs.

BPA Implementation Plan:

Adopt this recommendation by developing draft legislation in consultation with customers, constituents, employees, unions, the administration and the Northwest delegation. Such legislation would remove statutory barriers to improving the efficiency and effectiveness of human resource management and procurement and property management. These changes would give BPA greater flexibility to mold its internal administrative operations to the needs of the changing electricity industry and markets.

- Savings are estimated at $10 million per year in total, approximately $7 million of which would reduce PBL expenses.
- Issues '98 expense projections do not include these savings at this time. Although the Transition Board is now addressing this proposal, legislation has not yet been drafted, and regional, administration and congressional support is not yet clear.
- BPA cannot include these savings in its rate proposal until there is reasonable assurance that legislation will be enacted.

Customer Comment:

No comments received.

Cost Review Recommendations #10/11:

Federal Power Act conformance (cost allocation and functionalization) and reduced transmission internal costs.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$236.9 million/year - PBL transmission purchases
Cost Review Recommendation (Mar. 98):	$205.4 million/year - PBL transmission purchases
Cost Review Annual savings:	$30.0 million/year - reduction (power)/increase (transmission)
–from functional separation and FPA conformance	$1.5 million/year - from TBL cost reductions
Issues '98 Decision (Aug. 98):	$30.0 million/year - reduction (power)/increase (transmission)
– from functional separation and FPA conformance	$1.5 million/year - from TBL cost reductions

Cost Review Recommendation:

Further reduce transmission internal O&M expenses through improved efficiencies. Conform to functional separation and FPA requirements, adjusting and correcting allocation, functionalization and interbusiness-line transaction costs between power and transmission business lines.

BPA Implementation Plan:

Assume recommended cost savings to BPA's power business line.

- BPA's transmission business line has established a continuous performance improvement effort that relies on benchmarking to identify specific initiatives for cost-efficiency improvements throughout the organization and has a good recent track record.
- The adjustment and correction moving $30 million in estimated power costs to transmission is a very conservative assumption about interbusiness-line transactions and FPA conformance. These issues will be addressed in the upcoming rate case.

Customer Comment:

BPA has suggested cost shifts from power to transmission. BPA should not assume FERC FPA regulation will agree.

There are associated risks and challenges with implementation of most of the recommendations. As mentioned above, interbusiness-line transactions as well as FPA conformance issues will be discussed in the upcoming rate case. BPA's objective is to conform with FPA requirements for functionalizing costs.

Cost Review Recommendation #12:

Further reduce federal and non-federal debt service.

	(FY2002-06 Annual Average)
BPA Cost Baseline (Oct. 97):	$963 million/year
Cost Review Recommendation (Mar. 98):	$943 million/year
Cost Review Annual Savings:	$20 million/year
Issues '98 Decision (Aug. 98):	$20 million/year

Cost Review Recommendation:

Further reduce federal and non-federal debt service expenses through refinancings, greater reliance on variable rate debt and other debt reduction actions.

BPA Implementation Plan:

Adopt recommendation.

- Base for calculating savings: non-federal debt service and federal interest expense. Excludes interest credit on cash reserves and "capitalization adjustment" associated with Appropriations Refinancing Act.
- Achieving a full $20 million annual savings in Power Business Line may well require issuance of additional unhedged variable rate exposure, which carries higher financial risk.

Strategies

Refinance high-interest callable Treasury bonds.

- Limited restructuring of Treasury and Supply System debt for interest rate efficiencies. Issue Supply System variable rate debt up to asset/liability match.
- Redeem highest-cost fixed rate Supply System debt in open market while maintaining lower-cost variable rate debt.
- Reduce debt through revenue-financing new investment or accelerating repayment of existing debt to extent financial reserves and risk tolerances allow.

Key Assumptions

Refinancings can be completed while interest rates are relatively low.

- Impact on stakeholders – Net Billing Participants are not materially affected by restructuring of WNP-2 debt because all WNP-2 is debt still paid off by 2012.
- Bond counsel approval required for limited restructuring of WNP-2 debt.

Customer Comment:

No comments received.

Cost Review Recommendation #13:

Account for previously identified "undistributed reductions."

	(FY2002-06 Annual Average)
Cost Review Annual Savings:	$(19.4) million/year
Issues '98 Decision (Aug. 98):	$(19.4) million/year

Explanation:

These were already included in the PBL baseline expense projections. Thus, while the Cost Review's specific recommendations total $166 million for the Power Business Line, the net change from the power cost baselines is $145.7 million.

EXCERPTS FROM THE

Cost Review of the
Federal Columbia River Power System

Management Committee Recommendations

Cost Review of the
Federal Columbia River Power System
Management Committee Recommendations

Introduction

In 1997, the four Northwest governors asked the Northwest Power Planning Council (Council) to establish a cost control forum to assist the Bonneville Power Administration (Bonneville) in controlling the costs it recovers through rates preparatory to a subscription process for the post-2001 period. This Cost Review has covered planned costs of the Federal Columbia River Power System (FCRPS), including transmission, with a focus on projected costs for the 2002-2006 period. The objective has been to ensure that Bonneville's near and long-term power and transmission costs are as low as possible consistent with sound business practices, thereby enabling full cost recovery with power rates at or below market prices.

Following are the recommendations of the Cost Review Management Committee. They reflect the Committee's consideration of extensive public comment on its draft recommendations. In particular, the Committee has heeded the admonitions of many commentors to ensure that its recommendations for conservation and renewable resource development are consistent with the recommendations of the Comprehensive Review of the Northwest Energy System[1]. In addition, the recommendations regarding Washington Public Power Supply System plant 2 have been modified to respond to legal and operational issues that have been identified. These recommendations have been forwarded to the Bonneville Administrator and to the region's Governors and the House and Senate Committees on Appropriations in Congress. Responsibility for decision and action lies with the Administrator. The recommendations identify $137 million in reductions to FCRPS agency planned costs for FYs 2002-2006. These reductions are in addition to substantial cost cutting already undertaken. Fully implemented, the cost reductions identified herein and those identified in earlier Bonneville budget planning would result in annual power expenses in the FY 2002 – 2006 period that are over $200 million lower than Bonneville planned when rates were set for the current rate period, FYs 1997-2001.

The Management Committee included 11 members, including five "outside" experts in corporate management and finance, and representatives from both the Council and Bonneville. The outside members brought fresh business perspectives and the benefit of private-sector experience in leading large organizations through restructuring, cost cutting, and downsizing. The committee members were:

Curtis Bostick, Marco Island, Florida
Bostick is a personal investment manager who serves on the boards of numerous organizations, including two electric cooperatives in Florida and the Mariner Group, which operates nine hotels in the state.

Joyce Cohen, Portland, Oregon
Cohen served as one of Oregon's Council members until December 31, 1997, when her term expired.

Charles Collins, Seattle, Washington
Collins is president of Colsper West Corporation and a former member of the Northwest Power Planning Council. Collins chaired the 1996 Comprehensive Review of the Northwest Energy System.

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Jim Curtis, Portland, Oregon
Curtis is Bonneville's Senior Vice President for Business Services.

John Etchart, Helena, Montana
Etchart is chair of the Northwest Power Planning Council.

Steve Hickok, Portland, Oregon
Hickok currently is Bonneville's Acting Chief Operating Officer and formerly the, Senior Vice President for Power Business Line.

Mike Kreidler, Olympia, Washington
Kreidler is a former member of the United States House of Representatives, and he currently represents western Washington on the Council.

Robert J. Lane, Portland, Oregon
Lane is former president of the corporate banking group at U.S. Bancorp. Lane was president of West One Bancorp until August 1996.

Todd Maddock, Lewiston, Idaho
Maddock is chair of the Cost Review Management Committee and one of Idaho's two members on the Council.

Rosemary Mattick, Seattle, Washington
Mattick is Vice President of Procurement and Supply Management for the Weyerhaeuser Company.

William Vititoe, Seattle, Washington
Vititoe is the retired Chairman of the Washington Energy Company, a natural gas utility.

Background information is available on the Council's Web Site (www.nwppc.org/cost_rev.htm/). Also available is a summary of public comment received on the Committee's draft recommendations. Call the Council's public affairs division for more information: 1-800-222-3355 or 503-222-5161.

The Foundation: the Comprehensive Review of the Northwest Energy System

The Cost Review is an outgrowth of the Comprehensive Review of the Northwest Energy System[2]. The Comprehensive Review was a yearlong process initiated by the governors of the Northwest states, culminating in December 1996. The Comprehensive Review involved representatives of major interest groups from around the region. It focused much of its effort on Bonneville's role, obligations, and risks in a deregulated, competitive marketplace, and on aligning the risks and benefits of the Federal Columbia River Power System among customers, environmental imperatives, and taxpayers.

The primary goal of the Comprehensive Review was to ensure that the Bonneville Power Administration could continue to meet its obligations to the US Treasury and third-party debt holders, fulfill its responsibilities for fish and wildlife recovery, and retain the long-term benefits of the FCRPS for the Northwest. The Comprehensive Review also sought to define a role for Bonneville in the new competitive environment that was sustainable politically and competitively.

Key direction of the Comprehensive Review that has guided the Cost Review can be summarized as follows:

- Market the power products of the federal system for relatively long terms (5 years or more) to Northwest customers at cost based rates through a subscription system. This recommendation is central to achieving the primary goal of the Comprehensive Review.
- Return Bonneville to its historic role of marketing and transmitting power produced by the FCRPS, rather than becoming an aggressive marketer of power products and services in the competitive marketplace;
- End Bonneville's responsibility to acquire resources to meet the load growth of customers, except on a bilateral basis where the customer accepts the risk and financial obligations associated with such acquisitions;
- Limit Bonneville's financial support of conservation acquisition to current contractual obligations and certain market development activities, provided they are self-sustaining by 1999. Also limit support for conservation market transformation in proportion to the share of regional firm loads served by Bonneville;
- Define Bonneville's responsibility for renewable resource development (beyond current wind and geothermal pilot projects) to limited research, development and demonstration support, and to renewable resource purchases on the behalf of, and funded by, customer utilities; and
- Require Bonneville's transmission rates, terms and conditions to be designed and implemented in a manner which is comparable to those developed by investor-owned utilities subject to Federal Energy Regulatory Commission ("FERC") regulation.

In addition, the Comprehensive Review recommended that the responsibilities and funding of the Northwest Power Planning Council ("Council") be brought into line with the more limited role recommended for Bonneville.

[2] See *Toward a Competitive Electric Power Industry for the 21st Century*, Final Report of the Comprehensive Review of the Northwest Energy System, December 12, 1996. Document Number 96-CR26. The report can be obtained from the Northwest Power Planning Council

The Cost Review Goal

In July 1998, Bonneville will begin the subscription process recommended by the Comprehensive Review for selling its power products. The objective is to get new long-term power sales contracts in place for fiscal year (FY) 2002 through 2006 and beyond. Achieving a very high level of subscription by northwest wholesale power customers is a high priority. It is the most certain way to achieve the primary goal of the Comprehensive Review: - satisfying obligations to the U.S. Treasury and third-party bondholders; fulfilling responsibilities for funding fish and wildlife recovery; and retaining the substantial long-term benefits of the Federal Columbia River Power System (FCRPS) for the Northwest.

The work of the Cost Review Management Committee has been driven by the objective of achieving a high level of long-term Northwest subscription. However, Bonneville's wholesale customers are facing a period of unprecedented uncertainty and risk. There are new suppliers and increased price competition in the marketplace. With the onset of retail competition, utilities are uncertain of their future loads. It is the Committee's view that these utilities are unlikely to buy power from Bonneville on a long-term basis unless they perceive Bonneville's price to be very low relative to these risks. Thus, the Committee believes that the key to a high level of long-term subscription is to reduce the costs as much as possible, consistent with the Comprehensive Review and sound business practices. This would enable Bonneville to price its subscription products well below current market price expectations. Bonneville has been working toward a cost structure that would allow it to compete successfully in a 2 cent per kilowatt-hour market. The Management Committee has challenged Bonneville and other agencies of the power system (U.S. Army Corps of Engineers, the Bureau of Reclamation and the Washington Public Power Supply System) to beat that goal by a substantial margin.

The Committee believes that the goal of pricing power well below market expectations will enable Bonneville to return to its roots as envisioned by the Comprehensive Review. A focus on its core missions of marketing and transmitting the firm power output of the FCRPS for relatively long terms to regional customers, and of meeting its environmental responsibilities. This is a role that is sustainable, both competitively and politically. While Bonneville will continue short-term marketing of nonfirm power, the emphasis on long-term firm contracts will allow Bonneville to reduce staff and expenses associated with many marketing and related support activities. In this environment, Bonneville will not be engaged in acquiring additional power resources to meet the load growth of customers. Nor will it have a large responsibility for the development of conservation and renewable resources. Staffing and other expenses related to these activities can be reduced. These directions all are consistent with the recommendations of the Comprehensive Review of the Northwest Energy System.

The Committee's Starting Point: FCRPS "Cost Baselines" (October 1997)

Since late 1993, Bonneville has made substantial strides in reengineering its operations and reducing its planned costs. Indeed, FCRPS financial results for FY 1997 and reductions to date in Bonneville staffing demonstrate new, aggressive cost management practices. Bonneville staffing today is the lowest it has been since 1965. Recent efforts of the Bureau of Reclamation and the Washington Public Power Supply System (Supply System) to reduce costs and improve financial margins likewise reflect responsiveness to the marketplace for wholesale power.

In August and September of 1997, Bonneville completed its annual planning and budget process. This process covered the remaining four years of the current rate period (FY 1998-2001) and the initial five-year subscription period (FY 2002-2006). Bonneville already planned a number of cost-cutting actions beyond those reflected in the 1996 Rate Filing. These actions would result in average annual power expenses in the FY 2002-2006 period that are $89 million lower than the expenses planned to be recovered through Bonneville's rates for FYs 1997-2001. The results constitute the "Cost Baselines" that Bonneville proposed to the Management Committee for review and recommendation last October. Included were these cost management objectives in support of the Cost Baselines:

- Hold O&M in the Power Business Line (PBL), including other entities' O&M, flat over the 9-year (FY 1998-2006) horizon
- Manage WNP-2 operational costs to 19 mills/kWh by 2000and continue operation of project only if economic
- Limit renewable resource losses to no more than $15 million annually
- Pursue direct funding for future Corps/Bureau O&M and revenue-producing investments to enhance FCRPS market responsiveness
- Rigorously evaluate, prioritize, and manage revenue-producing Federal investments in hydro
- Constrain Bonneville-funded Federal investments to levels commensurate with the availability of low-cost sources of capital
- Reduce short- and long-term debt service costs through:
  1. refinancing whenever financial market conditions warrant,
  2. accelerated repayment of Federal debt or use of revenue financing when risk tolerances permit
- Manage relationships and fish costs to achieve measurable results in preserving and restoring PNW salmon
- Redesign information technology and accounting/financial reporting systems and services, to reduce overhead costs substantially while ensuring responsiveness to business needs
- Redesign other corporate services to reduce costs and increase value substantially
- Reduce Federal and contractor staffing per reengineering plans and corporate redesign targets
- Reduce funding for the Northwest Power Planning Council by 27 percent
- Reduce Energy Efficiency cost and staffing in order to achieve financial self-sufficiency by the end of 1999
- Continue implementation of a reliability-centered maintenance strategy for transmission
- Continue to shift from a long-run system expansion strategy to a customer request-based strategy for transmission investments
- Achieve superior performance compared to Western States Coordinating Council (WSCC) transmission providers (top one third), through operational efficiencies, and tighter control on timing, and prioritization of capital investments. This will result in a reduction to the fully allocated cost per hour of transmission maintenance service of 30 percent by 2001.

Included in the baselines for FYs 2002-2006 are assumptions that the costs of the Residential Exchange program are either eliminated statutorily or minimized through the "in lieu" provisions of the current statute, and that fish and wildlife costs remain stable. The Management Committee adopted these Cost Baselines as it's starting point.

FCRPS Cost Management Challenges and Opportunities

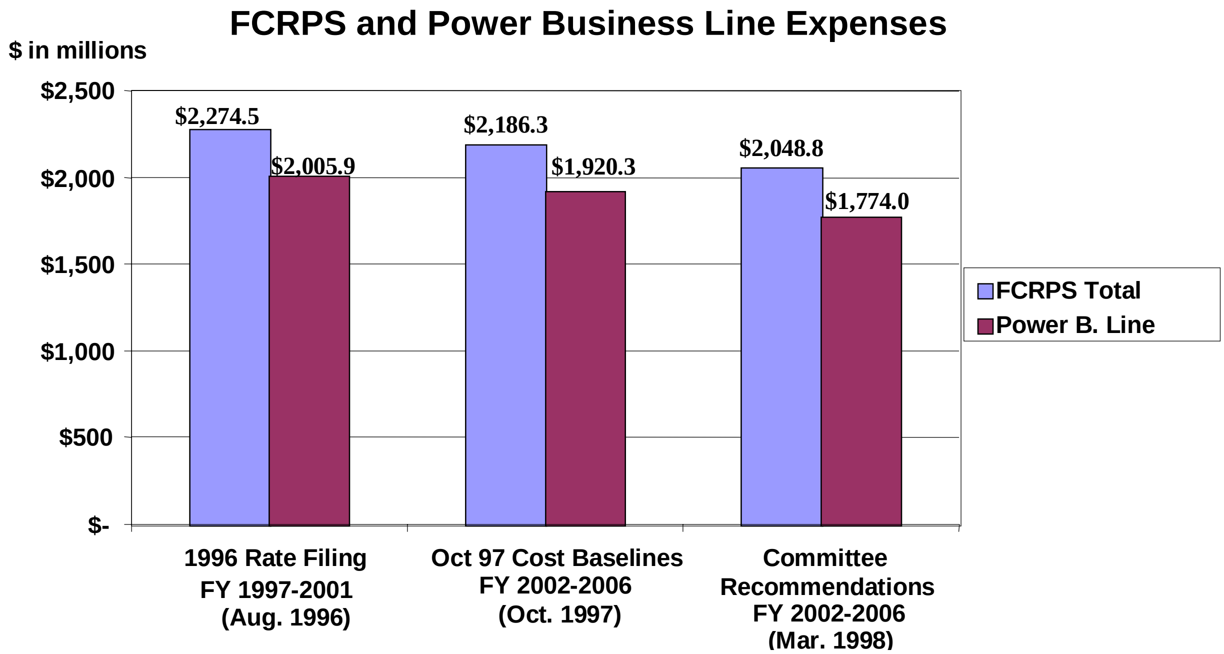
The Management Committee recognizes that Bonneville faces significant challenges and opportunities in achieving further savings; for example:

- System capability has suffered in recent years, in large part due to aging hydroelectric facilities and inadequate levels of appropriations funding. Improving productivity will require significant new investments that must be designed and managed to yield higher production and lower O&M costs.
- Unlike in a typical business enterprise, control over power production in the FCRPS resides largely with entities (i.e., Corps of Engineers, Bureau of Reclamation, Supply System) other than the entity responsible for marketing the products and recovering the costs (Bonneville). Almost half of power O&M costs and virtually all projected capital investments are managed by entities other than Bonneville. A consolidated, integrated strategy directed at maximizing FCRPS asset returns (financial results and public benefits) for the region is lacking.
- The Supply System has done an exemplary job in reducing its costs and increasing its production. It now projects that WNP-2 operating costs will be at or even slightly below expected market prices in the year 2000. However, beginning in 2002, the plant's costs may begin to increase, primarily due to a need to purchase fuel as the current inventory is depleted. These cost increases, as well as any unplanned expenditures, will need to be managed aggressively to minimize their impact.
- Most FCRPS expenditures for fish and wildlife, and other public responsibilities like the residential exchange, conservation, and renewable resource development, are borne by Bonneville's PBL, representing about 20 percent of this business line's expenses.
- Most of Bonneville's financial risks also fall to the PBL. At the same time, about 57 percent of this business line's expenses are attributable to relatively fixed debt service and depreciation expenses, due in large part to 100 percent debt financing of past capital investments.
- Bonneville's corporate functions and overheads generally are less efficient than "best practices" in other enterprises would indicate is possible.

The Management Committee's Recommendations

Bonneville should undertake extraordinary efforts in its power, corporate and transmission organizations to reduce the costs of its commercial operations and constrain the costs of its public benefit programs. Similarly, other agencies of the FCRPS -- the Corps of Engineers (Corps), the Bureau of Reclamation (Bureau), and the Supply System -- should act in concert with Bonneville by taking aggressive action to maximize the value of the FCRPS (financial returns and public benefits) by reducing O&M costs and improving asset productivity.

The Committee's recommendations are summarized in the following table and described in detail at the end of this document. If achieved by the FCRPS agencies, these cost reductions should permit Bonneville to price its subscription products significantly below currently expected market prices.


FCRPS and Power Business Line Expenses
$ in millions
$2,500
$2,000
$1,500
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$2,274.5
$2,005.9
$2,186.3
$1,920.3
$2,048.8
$1,774.0
FCRPS Total
Power B. Line
1996 Rate Filing FY 1997-2001 (Aug. 1996)
Oct 97 Cost Baselines FY 2002-2006 (Oct. 1997)
Committee Recommendations FY 2002-2006 (Mar. 1998)

Recommendations	Average Annual Reductions, FYs 2002-2006 $ in millions	
	Total Reductions	**Power BL Expense Reductions**
1. Further reduce staffing and support costs of power marketing and other PBL functions not directly related to operation of the Federal power system, through efficiency initiatives and reoriented long-term marketing efforts.	14.7	14.7
2. Fund regional conservation market transformation at a level proportional to the percent of regional firm load served by Bonneville, as called for in the Comprehensive Review. Reductions shown here bring the Cost Baseline into line with estimates of the firm power load served by Bonneville. Review the appropriateness of continued Bonneville support no later than 2004.	4.6	4.6
3. Reduce projected legacy conservation contract expenses to reflect historical under-spending. Do not modify or extend existing contracts, with the exception that the State's low-income weatherization contract should be extended consistent with the end of the legacy commitment to utilities. Reduce associated staffing.	2.5	2.5
4. Further reduce funding for the NW Power Planning Council to reflect changes in Bonneville's regional role (i.e., curtail new resource acquisitions), carry out the Council role in power recommended by Comprehensive Review and the continued importance of fish and wildlife issues. Seek additional funding from other sources for Council activities that are of regional scope. Reductions assume one Council representative per state. A process should be carried out to determine both the functions the region wishes the Council to perform and how the functions should be funded.	1.1	1.1
5. Provide funding for costs of the three renewable resource projects which Bonneville is currently planning for and currently planned levels of renewable resource data collection and R&D. Annual losses from project revenues and costs should not exceed $15 million per year, including the data collection and R&D costs. No additional renewable resource projects unless Bonneville's costs are fully recovered by project revenue.	2.2	2.2
6. Develop and implement a consolidated, integrated capital/asset management strategy for federal hydro directed at maximizing value, including both financial returns and public benefits. The strategy should encompass the operation and maintenance of the physical assets, a coordinated investment plan, potential consolidation of duplicative administrative support services among FCRPS agencies, and the creation of integrated performance measures. Performance should be measured explicitly and reported publicly, accountabilities established, and incentives created and applied FCRPS-wide. Estimates at right include a combination of reduced O&M expenses from the Cost Baseline and increased revenues from higher production.	Corps: 40.0 Bureau: 8.0	Corps: 40.0 Bureau: 8.0
7. Implement a strategy for WNP-2 that combines aggressive cost management with a flexible response to market conditions and unforeseen costs. Manage annual operating costs to annual revenues achievable at market prices. In BPA's subscription process and upcoming rate case, determine how to allocate the plant's costs in Bonneville rates and market a portion of the Federal Base System equivalent to the planned output of WNP-2 priced in a manner that ensures recovery of the plant's operating costs while allowing a lower price for the rest of the FBS, unless legal or other	19.0	19.0

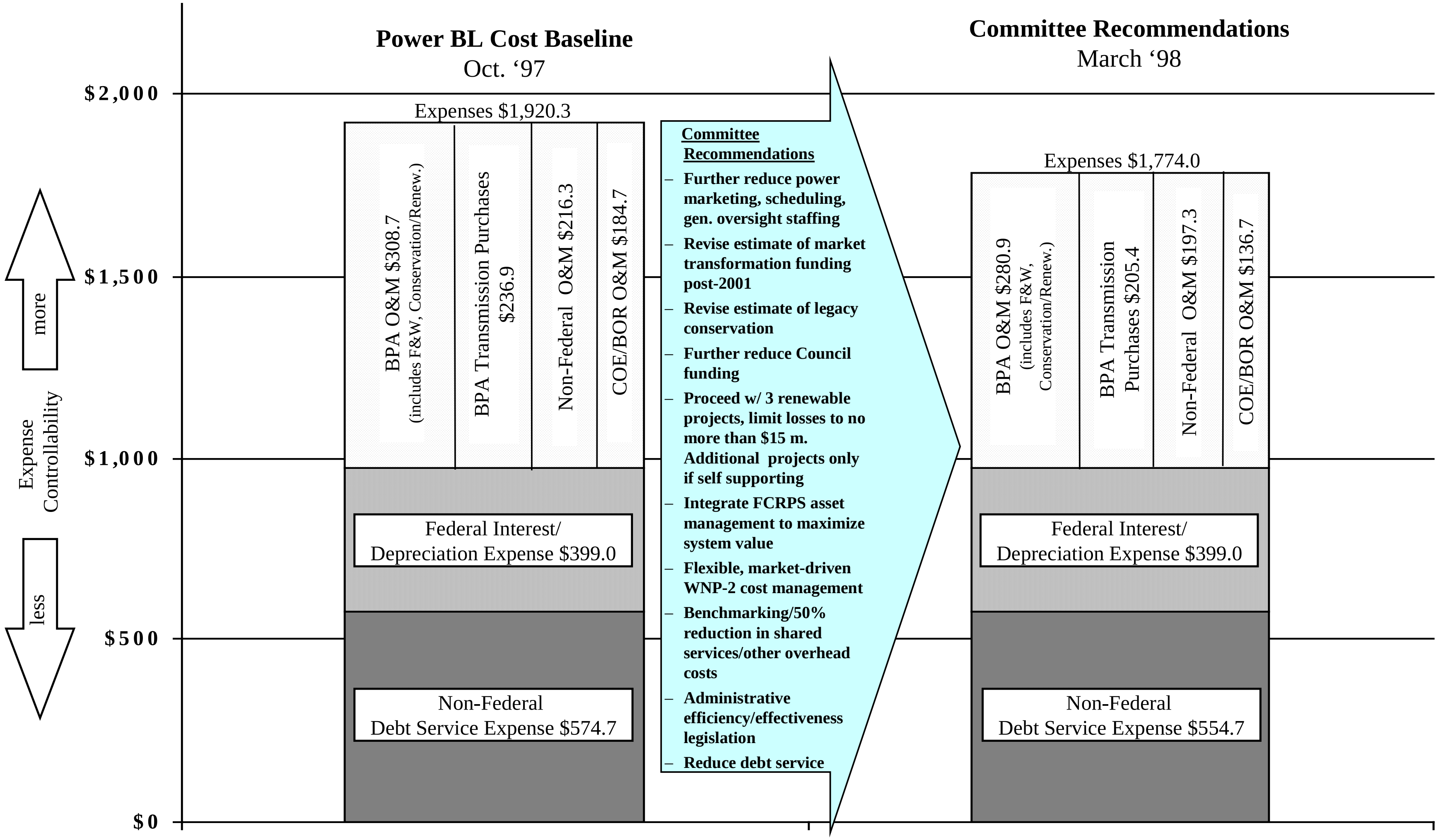
Recommendations	Average Annual Reductions, FYs 2002-2006 $ in millions	
	Total Reductions	**Power BL Expense Reductions**
issues prevent doing so. To the extent revenues exceed operating costs, use a portion of the resulting net operating revenues to build up the decommissioning fund. Biennially subject the plant to a market test. Consider termination in the event operating costs are projected to exceed revenues significantly, and re-evaluate termination if uneconomical at market prices. Estimated reduction includes a combination of reduced O&M expense from the Cost Baseline and potential increased revenues.		
8. Further reduce the cost of Bonneville administrative and other internal support service costs including financial, human resources, information management, procurement, strategic planning, public affairs, legal services and other internal service costs, by an aggregate 50 percent from 1996 actual levels. Achieve through benchmarking, adopting "best practices," enterprise software, and outsourcing of non-core functions where economic.	31.7	14.5
9. Obtain legislative changes in the areas of personnel management and procurement to improve administrative flexibility and ability to manage internal costs.	10.0	7.0
10. Further reduce transmission internal O&M expenses through improved efficiencies.	2.5	1.5
11. Conform to Federal Power Act requirements, adjusting and correcting functionalization (allocation) of costs between Power and Transmission business lines.	0.0	30.0
12. Further reduce federal and non-federal debt service expenses through refinancings, greater reliance on variable rate debt, and other debt reduction actions	20.0	20.0
13. Targeted, but unspecified reductions already included in Power Cost Baseline.	(19.4)	(19.4)
TOTAL	**136.9**	**145.7**

In addition, the Transmission Business Line should meet the cost management objectives in its baseline, in particular:

- Obtain operational efficiencies, tighter control on timing and prioritization of capital investments to achieve superior performance compared to the Western States Coordinating Council (WSCC) transmission providers (top one-third);
- Reduce fully allocated hourly costs of transmission maintenance service by 20 to 30 percent by 2001; and
- Increase flexibility of cost structure.

Recommendations would reduce Power BL expense projections by about $146 million

Average Annual Expenses - FY 2002-2006, $ in millions



Notes: Actual FY 1997 PBL expenses = $1,871.5 million
PBL cost baseline for FY 1997-2001 in the 1996 rate filing = $2,005.9 million
Committee recommendations for Corps, Bureau and WNP-2 are a combination of expense reductions and increased revenues. These are reflected here as a reduction in expenses only.

For several reasons, it is critical that Bonneville, the Corps, the Supply System, and the Bureau begin implementing these recommendations and the cost reductions already around in the October Cost Baselines as quickly as possible. Doing so will demonstrate to customers and other interests the commitment to aggressive cost cutting. Implementing some of the recommendations will entail new investment in systems and up-front costs to reduce staffing levels that can be paid for, in part, with near-term cost savings from early implementation. A large proportion of the savings is associated with implementation of an integrated asset management strategy. Forging such a strategy will take a concerted effort on the part of all the FCRPS agencies and is critical to improving the productivity of the FCRPS. Bonneville should move quickly to obtain Administration support for legislation to improve its administrative effectiveness and efficiency.

The Management Committee has not addressed fish and wildlife costs. The Committee believes there are opportunities for improved efficiencies in the planning and implementation of fish and wildlife measures on the part of Bonneville, the Council, the Corps, the Bureau, the National Marine Fisheries Service, the Fish and Wildlife Service, state agencies and the tribes. A management review of the contracting processes for implementing the fish and wildlife program was recently completed at the request of the Council.[3] This review identified recommendations for planning, procurement, contract administration, and monitoring that should result in a more cost-effective planning and implementation process. The same sort of scrutiny should be applied to the rest of the fish and wildlife activities. Efficiencies in fish and wildlife programs should be obtained with the same aggressiveness as the Committee is recommending in other functions of the FCRPS. Greater efficiency can only benefit fish and wildlife.

Several commentors expressed concern about follow-through on the Committee's recommendations. Bonneville's rate setting process will be the vehicle for implementation of many of the recommendations. That process provides opportunity for interested parties to see that the recommendations are being implemented. Other facets of the Committee's recommendations will require continuing attention over the long term. Bonneville and the Council should devise an approach for expert review and advise on long-term FCRPS cost management.

The Risks

Bonneville and the region face many risks in achieving the cost reductions discussed above. Implementing many of the recommendations will be difficult and success is not assured. There is no antidote for that, other than the skill and dedication of the managers and employees of Bonneville and the other FCRPS agencies. It is essential that these people be given the statutory authority and other tools necessary to be able to implement the cost reductions while maintaining the effectiveness of the agencies in carrying out their core functions.

Bonneville's financial risks are substantial. For the remainder of the current FY 1997-2001 rate period, hydro and thermal resource costs are the greatest risks to FCRPS net revenues. Market price risk during this period is limited due to sales contracts that are largely fixed. Financial risks are substantially greater post 2001, with added hydro risk, fish recovery and enhancement cost risk, and market price risk. The magnitude of the risks can be as much as $200 million or more in a given year. Bonneville can reduce its risk profile significantly by reducing its power costs and by creating greater flexibility in its cost structure over time. The Cost Baselines and the Committee's recommendations do not include two key elements of a Bonneville revenue requirement for power: (1) a planned margin (planned net revenues) for risk and (2) acceleration

[3] Columbia River Basin Fish and Wildlife Program - Management Review of Contracting Processes, Moss-Adams LLP, Certified Public Accountants, Portland, OR, December 1997

of repayment, as recommended by the Comprehensive Review when certain pricing conditions occur; i.e. when option fees are paid and when Bonneville's power costs are below market.

There is a risk that the sense of urgency in the need to reduce costs and improve productivity is not shared fully throughout the FCRPS agencies. Bonneville has been forced to confront this need by the realities of the market. Others have been insulated from those realities to varying degrees. In particular, the Management Committee concludes that the Corps must be more aggressive in reducing expenses and improving productivity. Implementation of an integrated capital/asset management strategy is essential if the FCRPS is to maximize asset value for the region.

The Supply System has made great strides in reducing costs and increasing availability. The Committee can anticipate a viable market for the power from WNP-2. However, the Supply System must reduce costs further to meet and sustain its year 2000 cost target, and the Committee has challenged it to produce even more savings. Toward this end, the Committee recommends the Supply System continue its examination of additional cost reduction measures and initiatives, including the potential adoption of a twenty-four-month fuel cycle, improved outage planning, industry benchmarking of "best practices", and the use of other fuel options. Unforeseen costs lower than expected market prices or performance problems could alter the situation. Increasing flexibility to deal with such circumstances should be a priority. If the plant is operated and marketed in a way that results in the generation of net operating revenues, the decommissioning fund should be built up to improve flexibility in the event the plant cannot recover its operating costs in the future.

Under the Northwest Power Act, Northwest utilities have the right to sell to Bonneville an amount of power equal to that required to serve their residential and small farm customers at their average system costs, and to receive an equal amount of power at Bonneville's average system cost. In reality, this has been an accounting transaction. The exchange was intended as a means of allowing wider access to the benefits of the federal hydro system. In the past, the exchange has been a major cost to Bonneville, but it cannot be allowed to be so in the future. The Comprehensive Review suggested an alternative way of providing access to the benefits of the federal system. It recommended that the residential and small farm customers of exchanging investor owned utilities be given the opportunity of being served with Bonneville power. Access to that power would be on a priority basis second only to public agencies. The Committee believes this can meet the objective of providing wide access to the benefits of federal power.

Bonneville now faces competition. Competitive markets mean price volatility, product innovation and aggressive marketing. Bonneville can limit its risks most appropriately in this environment by constraining its costs to levels that permit it to offer prices below market. The recommendations of the Cost Review will translate into low power prices only if subsidies and cost transfers inherent in the 1980 Northwest Power Act and in past Bonneville practices are held in check. At the time the Act passed, the argument was that these subsidies and cost transfers were affordable and necessary because Bonneville's costs were so far below market. The Committee's recommendations, seriously pursued, are designed to recreate those circumstances, but in a substantially changed market environment. Today's more competitive markets make discounts and subsidies less effective and less appropriate forms of public policy.

Finally, the Committee would like to conclude with a note of caution. The Committee realizes there are many calls on Bonneville's funds. But there is a need for restraint. To the extent the Committee's cost reductions are absorbed by increased expenditures for other purposes, the value of this Cost Review will have been diminished significantly. Driving Bonneville's costs back up to or above market levels will discourage subscription and jeopardize the fundamental goal of securing the long-term economic benefits of the federal system for the region. It will confirm to potential subscribers that Bonneville's costs are not manageable. Relying on stranded cost recovery mechanisms as an alternative to cost management is a high-risk path. If a high level of long-term subscription is achieved, long-term funding for fish recovery and other public benefits will be more stable; the US Treasury and other creditors will be more secure; stranded cost recovery mechanisms likely will be avoided; and, most importantly, the benefits of the Columbia River Power System will be retained in the Northwest.

UPDATES TO FORECAST OF GENERATION EXPENSES

As indicated in Fact Sheet No. 7, "BPA Targets Cost Savings, Close-Out on Cost Review Recommendations" (included in this Appendix), BPA is committed to achieving savings equivalent to the total recommended in the Cost Review. The recommendations called for annual power expense savings of $130.7 million, with additional revenue offsets of $15 million. Combined, the total recommended savings is $145.7 million. As shown in the following table, "Crosswalk from the Baseline used in the Cost Review to the Issues '98 Generation Expense Forecast," the Issues '98 expense forecast incorporated the full savings anticipated by the Cost Review, with the exception of recommendation No. 9, which called for $7.0 million in savings from legislative changes in the areas for personnel management and procurement to improve administrative flexibility. This savings amount was withheld pending reasonable assurance that such legislation will be enacted. (BPA continues to withhold these savings from this rate proposal). The Issues '98 generation expense forecast was $1,869.2 million (FY 2002-2006 annual average).

The annual generation expenses reflected in these revenue requirements are, on average, $504.6 million higher than the forecast shown in Issues '98. The details of this increase are shown in the accompanying table "Change in Generation Expense Forecasts since Issues '98". This expense increase is accompanied by an offsetting revenue increase of $33.3 million. The revenue increase, captured in the revenue forecast, reduces the costs that need to be recovered from rates. In summary, the net increase is due to:

(1) *Implementation of the Subscription Strategy, and expense changes resulting from the revenue requirements and rates development process.* In the Cost Review and Issues '98, expenses were developed using preliminary estimates of certain costs that are influenced by the Subscription Strategy and by the rates development process (*see* page 3 of Issues '98 Fact Sheet No. 7 in this Appendix). These costs, including system augmentation and balancing purchases (short-term power purchases) and the net costs of the proposed settlement of the REP, have been updated increasing average annual expenses by $494.6 million. For a fuller discussion of the Subscription Strategy and the power purchase expenses and Residential Exchange settlement expense required to meet, among other factors, higher loads than projected resource supply, please *see* the Wholesale Power Rate Development Study, WP-02-FS-BPA-05, and Wholesale Power Rate Development Study Documentation's, WP-02-FS-BPA-05A and WP-02-FS-BPA-05B, and Burns *et al.,* WP-02-E-BPA-08.

(2) *Implementation of the Principles.* As noted in Issues' 98 (*see* footnote to the table entitled "Projected FY 02-06 Average PBL Operating Expenses," page 2 of Issues '98 Fact Sheet No. 8 in this Appendix), the fish and wildlife funding amounts included in the Cost Review and in Issues '98 were based on a single, lower-cost funding alternative for fish and wildlife recovery O&M and capital recovery expenses. These amounts did not take into account the broad range of possible fish and wildlife funding requirements outlined in the Principles.

(3) The revenue requirements in this Study incorporate higher COE, Reclamation, and BPA O&M and capital recovery expenses to reflect the averaging of the O&M and capital investment costs of the 13 system configuration alternatives that is called for in the Principles (*see* Volume 1, Chapter 13 of Revenue Requirement Study Documentation,

WP-02-FS-BPA-02A) (average annual change: $65.0 expense increase, with an offsetting revenue increase of $5.0 million from non-fish and wildlife related activities, resulting in a net increase of $60.0 million);

(4) *Changes in costs caveated as subject to change in the revenue requirements and rate setting process.* The revenue requirement forecast incorporates a number of changes to cost areas that were acknowledged in the Cost Review and Issues '98 to be subject to change as revenue requirements and rates are set (*see* page 1 of Issues '98, Fact Sheet No. 8 in this Appendix). These include an updated estimate of GTA costs, the inclusion in the generation revenue requirement of the expenses and offsetting revenues associated with energy efficiency activities, and a new estimate of inter-business line transaction expenses reflecting revisions to both the forecasted amount and price of transmission purchases from BPA's TBL and a resolution of functionalization and ancillary services issues. Federal Power Act conformance issues, including functionalization and ancillary services, are addressed in DeWolf *et al.*, WP-02-E- BPA-13; DeClerck *et al.*, WP-02-E-BPA-26; and Homenick *et al.*, WP-02-E-BPA-27. (Average annual change: $107 million expense decrease, with an offsetting revenue increase of $13.3 million, resulting in a net decrease of $93.7 million);

(5) *Changes in savings estimates associated with Cost Review recommendations*. There is one correction in this category. This change represents a technical correction to the estimate of savings required to meet the Cost Review recommendation on internal administrative and support service costs. The Cost Review recommendation was to reduce the cost of BPA's administrative and other internal support service costs, including financial, human resources, information management, procurement, strategic planning, public affairs, legal services and other internal service costs, to 50 percent of 1996 actual levels. The Cost Review estimated that the reduction from the cost baselines needed to achieve this 50 percent level was $31.7 million, resulting in an expense level for internal administrative and support service costs of $25.1 million, with the generation function portion being $6.9 million (annual average for FY 2002-2006).

The Cost Review's estimate of the savings needed to achieve the 50 percent target were overstated. Actual 1996 results for the functions covered are an estimated $80 million, meaning that the cost target should be $40 million. Making this correction, and using the revised overhead allocation methodology incorporated in these revenue requirements, the spending level in the revenue requirement is an average of $16.8 million per year for FY 2002-2006 in the generation function, or $10.0 million higher than reflected in the Cost Review. Revisions to the methodology for overhead allocation are addressed in DeWolf *et al.*, WP-02-E- BPA-13.

With this correction, the savings incorporated in this revenue requirement from expense reductions associated with the Cost Review recommendations are $113 million, a difference of $18 million from the $131 million originally forecasted. As indicated, this difference is due to excluding the savings of recommendation No. 9 (Legislation to improve administrative effectiveness: $7 million) and the correction to recommendation No. 8 (Administrative and other internal services costs: $10 million).

GENERATION EXPENSES

Crosswalk of Final Proposal Revenue Requirement for FYs 1997-2001
to Final Proposal Revenue Requirement for FYs 2002-2006

Average During Period ($ in millions)

Description	Gen 1996 Final Rate Proposal FYs 1997-01*	Final Proposal Revenue Requirement FYs 2002-06	Difference	Remarks
Power Marketing & Scheduling	40.7	24.7	(16.0)	Reduced staffing and support services
Wheeling (GTAs)	36.9 *	52.0	15.1	Increase in GTA Costs
ST Prch Pwr / PNCA Intrchng	74.9	503.8	428.9	Includes purchases to supplement firm inventory to meet proposed firm power sales and balancing power purchases to enhance system flexibility
Generation Oversight	30.5	3.0	(27.5)	Termination of various generation contracts in FYs 1997-01
Conservation & Consumer Services	29.6	17.3	(12.3)	Phasing out of legacy conservation programs
Energy Efficiency O&M	0.0	11.2	11.2	Previously included in conservation, offset in large part by revenues
BPA Fish & Wildlife O&M	99.3	139.4	40.1	Ramp up from current MOA to spending assumption in fish funding principles
CSRS Pension Expense	0.0	17.1	17.1	New requirement: fully fund Civil Service pension and post-retirement benefits
Administrative & Support Services	--	16.8	16.8	1996 rates included corp. expenses of $16.1m, distributed over several cost line items; these are now shown in aggregate in rev. requirement. The $16.8 m is consistent with Cost Review recommendation to reduce agency administrative and support services costs at 50% of '96 actuals
Planning Council	8.2	5.1	(3.1)	Cost Review; reduction may require legislation
Corps of Engineers O&M	97.8	111.2	13.4	Ramp-up in fish O&M per fish funding principles. Generation O&M held flat at 1996 actual levels
U.S. Fish & Wildlife O&M	16.9	17.1	0.2	
Bureau of Reclamation O&M	39.7	48.0	8.3	Cultural resource mitigation and higher fish investment
Colville Settlement	15.3	16.0	0.7	
Renewable Projects	6.1	20.0	13.9	Consistent with Comp & Cost Reviews; revenue offsets limit losses to no more than $15m/yr
WNP-1 & WNP-3 Preservation Costs	3.3	3.5	0.2	
WNP-2 O&M/Capital Requirements	164.7	168.5	3.8	Additional decommiss. costs; purch of nuclear fuel; Cost Review savings relected as rev enhance.
Trojan Decommissioning	18.0	4.3	(13.7)	
Between Business-line Expense	295.4 *	135.2	(160.2)	Cost of purchasing transmission service (under Subscription, primary products are undelivered power). In '9(rate case, all power was delivered product)
LT Power Purchases	22.0	27.8	5.8	
Non-Federal Projects Debt Service	601.0	568.2	(32.8)	Refinancing (principle reshaped and interest reduced)
Conservation Financing	7.5	5.6	(1.9)	
Federal Projects Depreciation	171.9	175.3	3.4	
Net Res Exch (IOU Sub. Settlement)	89.4	69.7	(19.7)	FY 2002-2006 IOU Subscription Settlement Payments: difference BPA's est cost to purchase 800 MW and revenue if sold @ PF
Net Federal Interest Expense	224.4	213.0	(11.4)	Higher interest credit due to reserve levels, higher interest due to fish recovery obligations
Total	**2093.5 ***	**2373.9**	**280.4**	

** Adjustments for comparison purposes. In 1996 rate proposal, wheeling costs were functionalized to transmission, not power, and "between business line expenses" were the portion of the transmission revenue requirement that was included in bundled power*

NOTE: this table does ***not*** include planned net revenue component of revenue requirement

Crosswalk of the Cost Review Baseline to the Issues '98 Generation Expense Forecast

($ in millions, FY 2002-2006 averages)

	Revenue Offsets	Expenses
Cost Review Baseline		$ 1,920.2
Cost Review Recommendation Reductions	*$ (15.0)*	*$ 130.7*
Cost Review Baseline less Recommendation Reductions	$ (15.0)	$ 1,789.5
Issues '98 changes to Cost Review Recommendations		
Savings from legislation to improve administrative efficiency/effectiveness (Cost Review Recommendation#9) not included in Issues '98 expense estimates pending development and support for legislation		$ 7.0
Changes in Other Costs Not Covered by Cost Review recommendations		
Increase in Wheeling expenses due to requirements under General Transfer Agreements		$ 28.2
Change to expense portion of interbusiness line transactions		$ 63.9
Revised estimate of Short Term power purchases		$ (5.5)
F&W direct costs revised to include inflation (inadvertantly left out of Cost Review Baselines)		$ 9.0
Revised forecast of Interest including impact of cost reductions on cash balances and other changes to outstanding debt		$ (10.9)
Revised forecast of Depreciation		$ (16.6)
Miscellaneous revisions		$ 4.6
Issues '98 Forecasts	$ (15.0)	$ 1,869.2

Change in Generation Expense Forecasts Since Issues '98

($ in millions, FY 2002-2006 averages)

	Revenue Offsets	Expenses
Issues '98 (Sept. 98)	**(15.0)**	**1869.2**
Changes in Costs Due to Implementation of the Subscription Strategy and Rates Development		
Increase in short-term power purchases (includes system augmentation) mainly to accommodate inventory shortfalls		**425.1**
IOU subscription settlement payments: difference between BPA's estimated cost to purchase the 800 aMW and estimated revenue if the 800 aMW sold at market		**69.5**
Changes in Costs Attributable to Fish and Wildlife Funding Principles		
Increase in BPA FWL (direct program) O&M; Issues '98 assumed a low-point forecast of $106 million, whereas the Principles call for an average estimate between the low and high cost alternatives ($139 million)		**33.0**
Corp O&M; increased from Issues '98 to reflect the Principles, while accommodating requirements of the hydro system	**(5.0)**	**22.0**
Increase in Federal interest expense due to lower reserve assumptions and lower interest earnings, and higher projected investment for fish spending		**10.0**
Changes in Costs Not Covered by Cost Review recommendations		
Increase in wheeling expense due to GTA's. Issues '98 included $40 million for GTA's. BPA now forecasts an additional $10 million for an average annual total of $50 million in generation function		**10.0**
Inclusion of Energy Efficiency spending and revenues in power rates	**(13.3)**	**11.2**
Changes to expense portion of interbusiness line transactions reflecting revised forecasts of both the price and amount of transmission services purchases		**(128.2)**
Changes in Costs Included in Cost Review Recommendations		
Correction to Cost Review savings target in administrative & support services costs also reflects change in method of allocating corporate overhead (shown is impact on generation expense)		**9.9**
WNP-2 operations due to 2-year refueling cycle	**(15.0)**	**15.0**
Remove placeholder for Debt Service Savings (Cost Review Recommendation #12), shown as an undistributed expense reduction in Issues '98		**20.0**
Miscellaneous Small Changes		**7.2**
Subtotal Changes in Offsetting Revenues and Expenses since Issues '98	***(33.3)***	***504.6***
Total Offsetting Revenues and Expenses in Final Proposal - May '00	**(48.3)**	**2373.9**

APPENDIX B

THE REPAYMENT PROGRAM

1. REPAYMENT PROGRAM OPERATION

1.1 Purpose

The major purpose of the repayment program is to determine, consistent with applicable Federal statutes and RA 6120.2, whether a given set of annual revenues is sufficient to repay with interest the long-term obligations of the FCRPS. The program calculates amortization and interest when determining the minimum revenue level necessary to recover these obligations.

1.2 Computation of Revenues Available for Interest and Amortization

Given a set of revenues and expenses for each year, a set of annual revenues available for interest and amortization can be obtained by subtracting non-investment-related expenses such as O&M expense, purchased power, and exchange costs from revenues (equation 1 below). This revenue subset can then be used to make interest expense and amortization payments on FCRPS-related appropriations and bonds.

$$(1) \quad \text{revenues available for interest and amortization}_i = \text{revenues}_i - \text{expenses}_i, \qquad i=1,2,...,n,$$

where n is the total number of years in the study.

1.3 Computation of Revenues Available for Amortization Payments

For each year, the revenues available for interest and amortization, less interest expense, are used to make amortization payments on the Federal investments and obligations (equation 2 below). It should be noted that the repayment program recognizes the unique nature of <u>each</u> of the Federal investments and associated obligations. The program uses data for all specific investments for generation. The project name, amount of principal, interest rate, in-service date, due date, and the nature of the investment are described for each investment.

$$(2) \quad \text{revenues available for interest and amortization}_i - \text{interest expense}_i = \sum_{j=1}^{m} \text{amortization payment}_{ij}, \qquad i=1,2,...n,$$

where m is the total number of Federal investments.

1.4 Computation of Principal Payments Given Due Dates

The amortization payments on each investment must total the investment's principal on or before its due date (equation 3):

$$(3) \quad \sum_{i=1}^{n} \text{payment}_{ij} \leq \text{principal}_j, \qquad j=1,2,...m.$$

1.5 Ordering of Payments According to Highest Interest First Constraint

The process described above yields one set of equations in which the payments are summed by year and another set of equations in which the payments are summed by investment. Taken together, however, these two sets of equations have no unique solution. RA 6120.2 suggests an approach to a unique solution with the requirement that "[t]o the extent possible, while still complying with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accompanied by application to the highest interest-bearing investment first."

A new equation can be obtained for each year by adding together equation 2 for that year and all earlier years. This equation sums all amortization payments made on any investment that comes due in those years. This equation can be simplified by substituting the principal of each such investment for the sum of the amortization payments on that investment as given by equation 3. The resulting equation (equation 4 below) indicates that for any year the sum of amortization payments on obligations that are not due by that year cannot exceed the sum of the revenues available for interest and amortization less the accumulated interest expense and the accumulated principal of all investments that are due in, or prior to, that year.

$$(4) \quad \sum_{i=1}^{k} \text{revenues available for interest and amortization}_i - \sum_{i=1}^{k} \text{interest expense}_i - \sum_{\text{due}} \text{principal}_j = \sum_{\text{not due}} \sum_{i=1}^{k} \text{payment}_{ij}, \qquad k=1,2,...,n.$$

The term "<u>due</u>" refers to Federal obligations due to be repaid in or prior to the year k, and "<u>not due</u>" refers to Federal obligations not due to be repaid by the year k.

For each year in the repayment study, the right side of equation 4 represents the amount of the accumulated amortization payments on Federal obligations that are not due. The left side of the equation represents the accumulated revenues available for making these payments on the Federal obligations. These amortization payments will first be made on the highest interest bearing Federal obligations in compliance with RA 6120.2. If for some future year this amount is evaluated as being zero or negative, then this equation implies that amortization payments can be made only on highest interest bearing Federal obligations that come due on or before that year.

1.6 Iteration Towards A Solution

Equations 2 through 4 do not permit a direct solution. Although the revenues and the Federal obligation that are due are known for all years, an amortization payment made in the current year will affect interest expense in future years. That is, interest expense will no longer have to be paid on the portion of the Federal obligations that has been amortized. This problem is solved using an iterative approach.

The program initially assumes no future interest expense in evaluating the left side of the fourth set of equations. Consequently, the net revenues available for payments on Federal obligations that are not due, but bear the highest interest rates, will be excessive. As payments are determined for each successive year, and the interest expense of a given year is calculated, they are used in the fourth set of equations for all later years. The fourth set of equations is thus modified, and the revenues available for payments on "not due" highest interest rate bearing Federal obligations are reduced. Therefore, the amortization of a Federal obligation on its due date, in order to satisfy equation 3, may violate equation 2. Equation 2 may be violated when a negative balance occurs. A negative balance will result when revenues available for interest and amortization are less than interest expense plus any amortization payments that are due. As a result, a second iteration is necessary.

In the second iteration, the interest expense developed in the first iteration is used in the fourth set of equations for future years. Since amortization payments on "not due" highest interest rate bearing Federal obligations were excessive in the first iteration, the interest expense developed in the first iteration will be less than the true interest expense. These estimates, however, are more accurate than an estimate of zero interest expense and, as a result, the negative balances will be reduced.

If revenues are sufficient to recover a given set of annual expenses and to repay with interest BPA's long-term Federal obligations, then the interest expenses of successive iterations will converge and the negative balances will be reduced to zero and, thus yield a solution. Under these conditions all four equations will be satisfied.

If revenues are insufficient, then compliance with the fourth set of equations will force amortization payments on the highest interest obligations to be delayed. This will cause an increase in interest expense, leaving less revenue available to amortize high interest obligations. The interest expense from successive iterations will diverge, and the negative balances will start increasing. Under these conditions no solution is possible given available revenues.

BPA does not deliberately plan to defer annual expenses in the future. Therefore, if revenues were insufficient to cover annual expenses for any year of the repayment period, the program decides that no solution is possible at that revenue level.

2. DETERMINING A SUFFICIENT REVENUE LEVEL

As noted above, the repayment program is also used to determine a minimum revenue level sufficient to meet a given set of repayment obligations.

A set of trial revenues can be obtained by multiplying a set of given revenues by a factor. A factor is an assigned real number. If the set of trial revenues obtained with a factor is found to be insufficient, then all lower factors are known to produce insufficient revenues. If some other factor is found to produce sufficient revenues, then all higher factors are known to produce sufficient revenues. Therefore, only intermediate factors need to be tested.

Testing any intermediate factor establishes one of two propositions: (1) that either it and all lower intermediate factors are excluded; or (2) that it and all higher intermediate factors are included. In this manner, the set of intermediate factors is reduced. Through this repeated testing (referred to as the binary search technique), the set of intermediate factors is reduced to a size determined by a preset tolerance limit (the tolerance level of the current study is set at .005 percent of the given revenues).

The lowest factor that is determined to produce sufficient revenues in accordance with this testing procedure will produce the <u>minimum</u> revenue level, within the accuracy of the program, that meets <u>all</u> repayment obligations with interest subject to the conditions specified in RA 6120.2 and relevant legislation.

3. TREATMENT OF BONDS ISSUED TO U.S. TREASURY

BPA's current long-term bonds issued to the U.S. Treasury consist of term bonds and callable bonds. The term bonds cannot be prepaid, so their amortization and the revenues required therefore are excluded from the above calculations. The remaining bonds are callable bonds and have provisions that allow for early redemption before the maturity date—five years after the date of the issuance on some older bonds and longer periods on some of the more recently issued bonds. In addition, a premium must be paid if a bond is repaid before its due date. The premium that must be paid decreases with the age of the bond. This premium affects the repayment process in two ways.

First, such premiums must be included with the payments of equation 2 and consequently affect the fourth set of equations. The premium that is paid on any Federal bond is considered to be due when the Federal bond is due. The premiums of one iteration are accumulated by due year and included in the fourth set of equations for the following iteration. When each premium is paid in the following iteration, it is used to modify the fourth set of equations and is also accumulated in case another iteration is necessary.

Second, the decrease in the premium that must be paid also affects the highest interest selection process. This effect is equivalent, in total, to a fixed premium and a reduced interest rate. This reduced effective interest rate enters into the comparison with other Federal investments and obligations to determine which should be repaid first.

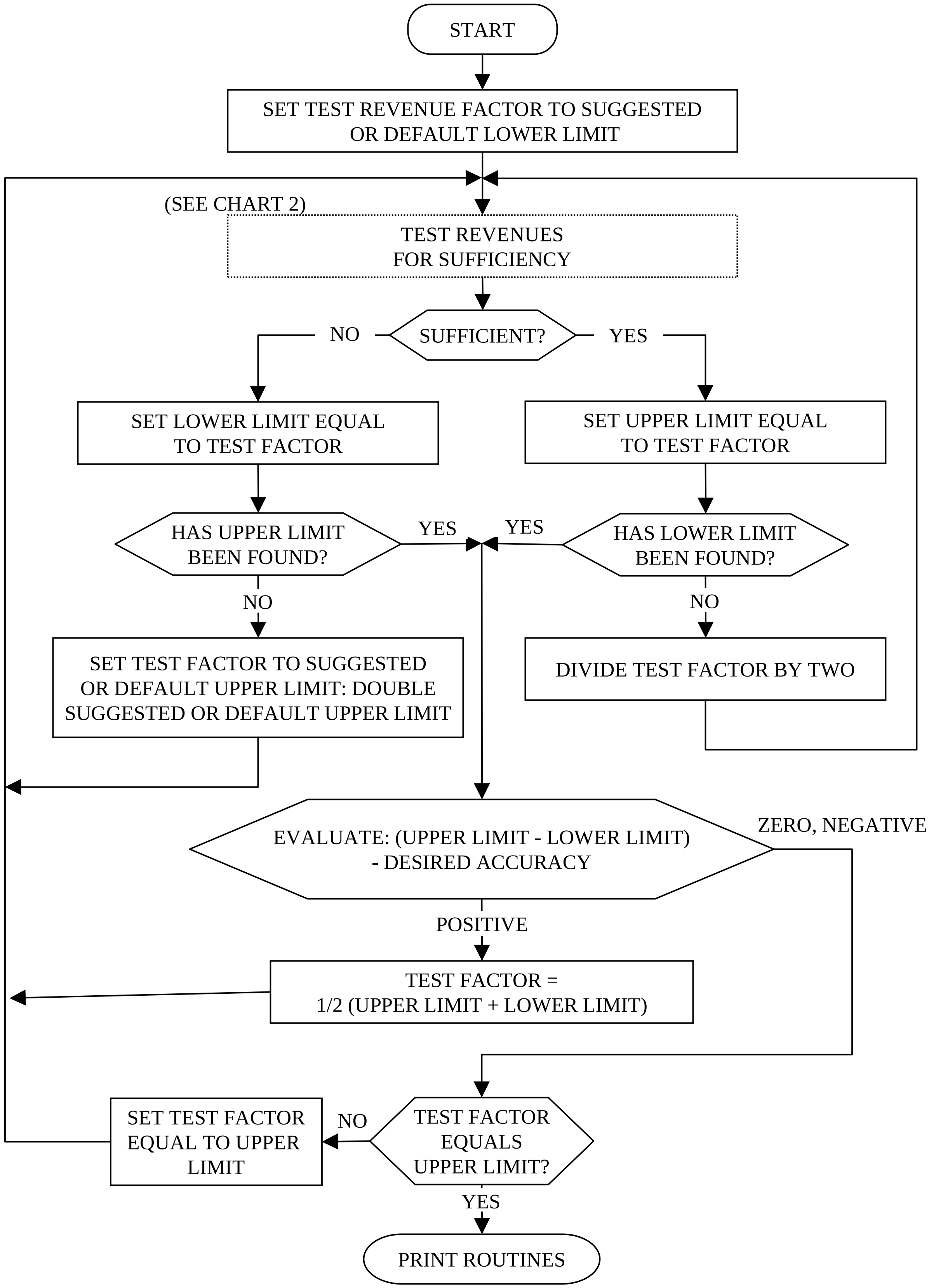
4. INTEREST INCOME

BPA is authorized by applicable legislation and RA 6120.2 to calculate interest income as a credit to interest expense. An interest income credit is computed within the repayment program based on the average cash balance of funds required to be collected for return to the U.S. Treasury in that year. The program assumes that the cash accumulates at a uniform rate throughout the year, except for interest paid on bonds issued to the U.S. Treasury at midyear. At the end of the year the cash balance together with the interest credit earned thereon is used for payment of interest expense, amortization of the Federal investment and payment of bond premiums.

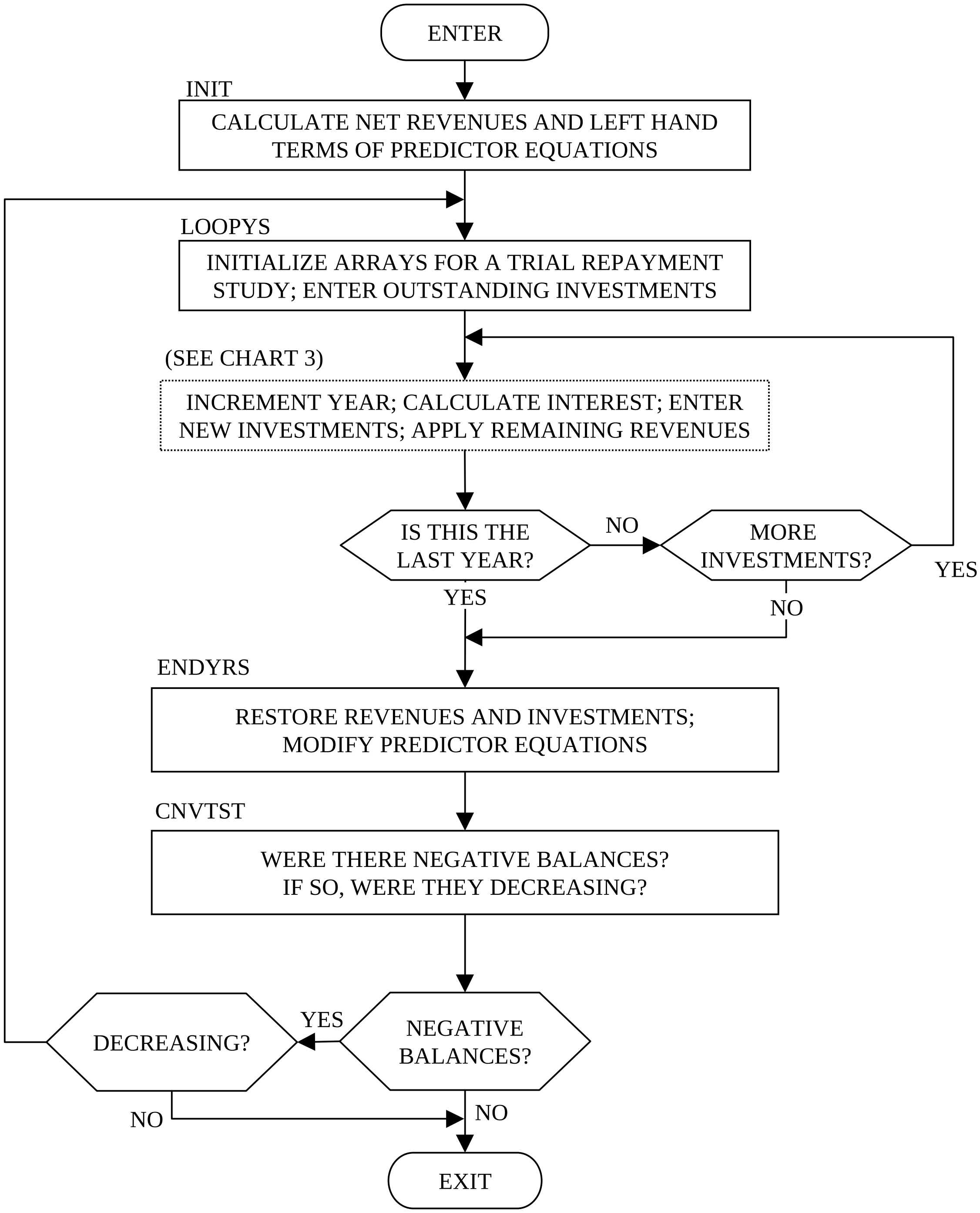
5. FLOW CHARTS

The following three pages contain flow charts associated with the repayment study program. The first chart shows the binary search process. The second chart shows the test for sufficiency. The third chart shows the application of revenues. *See* Volume 2, Chapter 11 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02B.

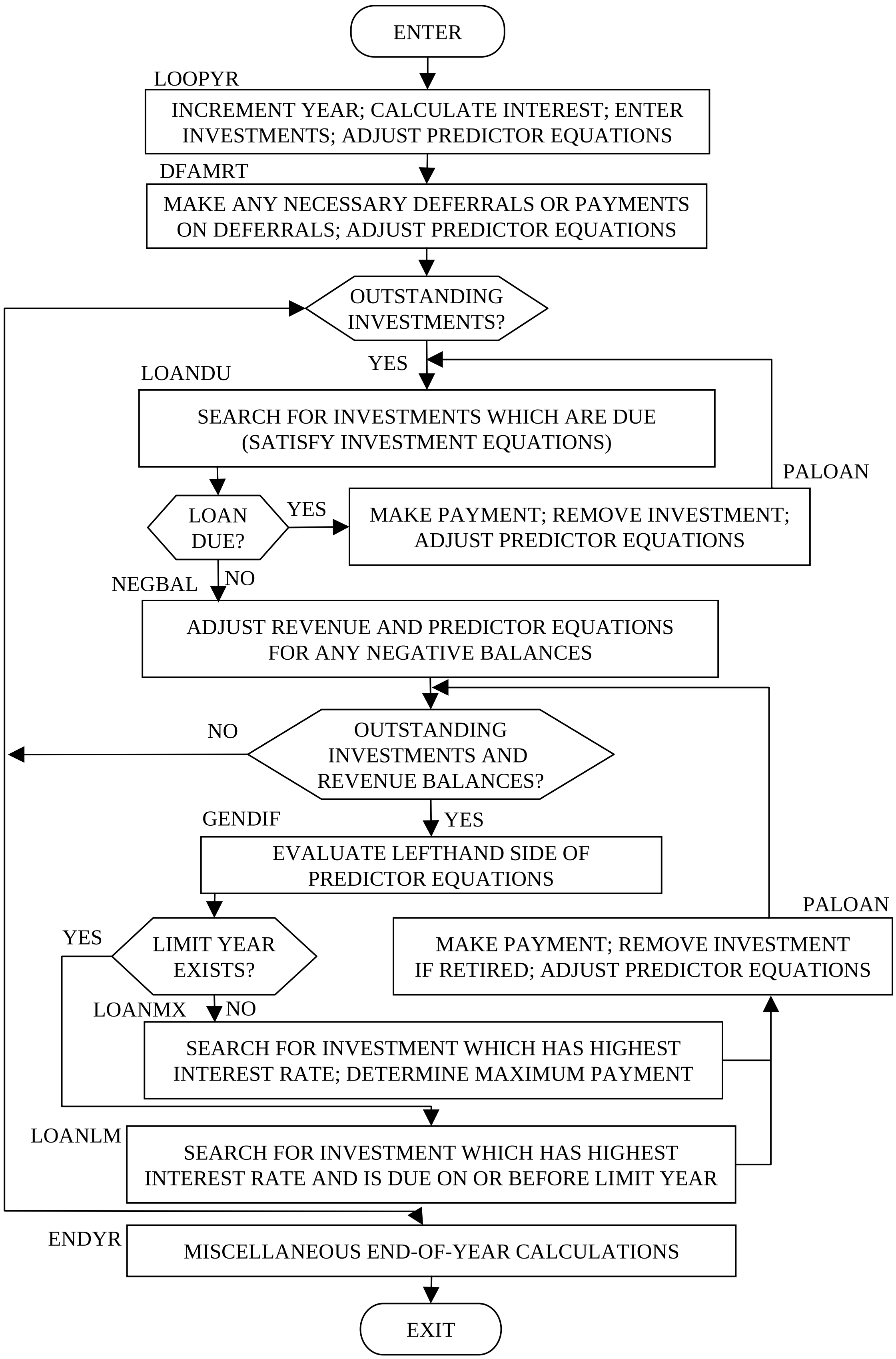
REPAYMENT PROGRAM
(BINARY SEARCH)
CHART 1



REPAYMENT PROGRAM
(TEST FOR SUFFICIENCY)
CHART 2



REPAYMENT PROGRAM
(APPLICATION OF REVENUES)
CHART 3



6. DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table 10 shows the amortization results from the Generation repayment studies for FY 2002-2006, summarized by bonds, appropriations and irrigation due and discretionary, by year.

Tables 11 through 15, A through G, show the results from the Generation repayment studies for FY 2002-2006, respectively, using revenues from current rates. Table 16 provides the application of amortization through the repayment period for generation based upon the revenues forecast using current rates.

Tables 11A-15A display the repayment program results for generation for FY 2002-2006. Column A shows the applicable FY. Column B shows the total investment costs of the generating projects through the cost evaluation period. *See* Volume 1, Chapter 4 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A. In Column C, forecasted replacements required to maintain the system are displayed through the repayment period. *See* Volume 1, Chapter 11 of Revenue Requirement Study Documentation, WP-02-FS-BPA-02A. Column D 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.

In Column E scheduled amortization payments for generation are displayed for each year of the repayment period. Discretionary amortization (Column F) shows generation amortization payments made after the "critical year" but before the due dates of each particular project. (The critical year is defined as the last year of the repayment period during which the optimization of interest and amortization requires that the annual costs, interest, and amortization equal the minimum revenue level; this is made manifest by amortization payments approaching zero or retiring only obligations which could not be prepaid and are due.) Unamortized generation obligations, shown in Column G, are determined by taking the previous year's unamortized amount, adding any replacements, subtracting amortization and subtracting discretionary amortization. Columns H, I, and J 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-15B display planned principal payments by FY 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-15C 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-15D show the planned interest payments by FY for Federal generation obligations. Shown on these tables are the interest payments associated with the appropriations of the COE and Reclamation, and BPA bonds.

Using the same format as Tables 11C-15C, Tables 11E-15E detail the component of capitalized contractual obligations associated with the payment of interest expense on these bonds.

Tables 11F-15F provide a summary of all principal and interest payments associated with generation obligations. Columns B and C represent the principal portion of the conservation and generation and capitalized contractual obligations. Column D is the total principal payment. Columns, E and F represent the interest portion of the conservation, generation, and capitalized contractual obligations. Column G is the total interest payment.

Tables 11G-15G 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 B shows unamortized obligations and is identical to the data shown in Column G of Tables 11A-15A. Column C shows obligations that are due for each year. It should be noted that 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 be zero at the end of the repayment period because of the replacements occurring subsequent to the cost evaluation period.)

Table 16 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 - GENERATION
REPAYMENT STUDY FOR FINAL PROPOSAL 2002
FY2002 - 2006
(000s)

Maturing/Due		
Bonds		
	2002	66,000
	2003	25,622
	2004	27,400
	2005	0
	2006	0
		119,022
Appropriations		
	2002	0
	2003	20,440
	2004	56,464
	2005	103,173
	2006	53,200
		233,277
Irrigation Assistance		
	2004	739
		739
	TOTAL	**353,038**

Scheduled But Not Yet Due		
Bonds		
	2002	0
	2003	0
	2004	0
	2005	30,757
	2006	0
		30,757
Appropriations		
	2002	41,401
	2003	26,922
	2004	8,421
	2005	14,167
	2006	75,276
		166,187
	TOTAL	**196,944**

Total by Year		
Bonds		
	2002	66,000
	2003	25,622
	2004	27,400
	2005	30,757
	2006	0
		149,779
Appropriations		
	2002	41,401
	2003	47,362
	2004	64,885
	2005	117,340
	2006	128,476
		399,464
Irrigation Assistance		
	2004	739
		739
Total		
	2002	107,401
	2003	72,984
	2004	93,024
	2005	148,097
	2006	128,476
		549,982

FEDERAL COLUMBIA RIVER POWER SYSTEM
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)

GENERATION

A	B	C	D	E	F	G	H	I	J
	INVESTMENT PLACED IN SERVICE						IRRIGATION ASSISTANCE		
FISCAL YEAR ENDING SEPT 30	INITIAL PROJECT THRU 9-30	CUMULATIVE REPLACEMENTS THRU 9-30	= AMOUNT IN SERVICE	- AMORTIZATION 9-30	- DISCRETIONARY AMORTIZATION	= CUMULATIVE UNAMORTIZED INVESTMENT	AMOUNT IN SERVICE	- AMORTIZATION	= UNAMORTIZED AMOUNT
CUMULATIVE 1999	5,443,896	179,484	5,623,380	1,692,013		3,931,367	770,437		770,437
2000	210,182		5,833,562	50,115	40,316	4,051,118	770,437		770,437
2001	612,002		6,445,564	19,474	34,313	4,609,333	770,437	16,560	753,877
2002	261,737		6,707,301	66,000	41,412	4,763,658	770,437		753,877
2003			6,707,301	46,062	20,332	4,697,264	770,437		753,877
2004			6,707,301	82,522	1	4,614,741	770,437	739	753,138
2005			6,707,301	103,173	39,372	4,472,196	770,437		753,138
2006			6,707,301	53,200	65,460	4,353,536	770,437		753,138
2007			6,707,301	61,710	45,000	4,246,826	770,437	2,931	750,207
2008			6,707,301	104,300		4,142,526	770,437	19	750,188
2009			6,707,301	118,115	2,120	4,022,291	770,437	7,709	742,479
2010			6,707,301	62,726	65,575	3,893,990	777,379	6,566	742,855
2011		253,719	6,961,020	43,569	75,879	4,028,261	777,379		742,855
2012		36,130	6,997,150	55,618	40,898	3,967,875	780,855	811	745,520
2013		170,371	7,167,521	152,800	108,940	3,876,506	800,648	87,326	677,987
2014		69,173	7,236,694	61,080	255,089	3,629,510	800,648	48,554	629,433
2015		189,697	7,426,391	147,000	182,453	3,489,754	805,755	54,101	580,439
2016		123,371	7,549,762	92,593	216,528	3,304,004	811,149	99,517	486,316
2017		141,541	7,691,303	88,572	349,979	3,006,994	811,149	62,246	424,070
2018		338,485	8,029,788	54,844	604,338	2,686,297	862,336	25,460	449,797
2019		17,939	8,047,727	6,179	418,249	2,279,808	873,238	88,259	372,440
2020		26,290	8,074,017	32,583	464,944	1,808,571	873,238	36,743	335,697
2021		144,610	8,218,627	69,828	487,452	1,395,901	912,445	16,826	358,078
2022		208,162	8,426,789	27,396	524,769	1,051,898	951,494	44,911	352,216
2023		89,275	8,516,064	1,555	610,560	529,058	951,494	9,663	342,553
2024		2,871	8,518,935	103	531,826		993,300	138,659	245,700
2025		197,923	8,716,858		197,923		1,013,337	185,752	79,985
2026		80,725	8,797,583		80,725		1,013,337		79,985
2027		185,983	8,983,566		185,983		1,045,565		112,213
2028		200,689	9,184,255		200,689		1,078,951	44,797	100,802
2029		164,432	9,348,687		164,432		1,078,951		100,802
2030		34,177	9,382,864		34,177		1,108,914		130,765
2031		135,453	9,518,317		135,453		1,138,877	44,797	115,931
2032		126,534	9,644,851		126,534		1,138,877		115,931
2033		56,523	9,701,374		56,523		1,179,301		156,355
2034		38,147	9,739,521		38,147		1,219,725	29,207	167,572
2035		170,807	9,910,328		170,807		1,219,725		167,572
2036		69,159	9,979,487		69,159		1,248,274		196,121
2037		108,915	10,088,402		108,915		1,276,982	29,310	195,519
2038		12,169	10,100,571		12,169		1,276,982		195,519
2039		141,511	10,242,082		141,511		1,306,293		224,830
2040		576	10,242,658		576		1,340,128	33,836	224,829
2041		106,565	10,349,223		106,565		1,340,128		224,829
2042		52,748	10,401,971		52,748		1,374,822		259,523
2043		49,316	10,451,287		49,316		1,409,517	32,941	261,277
2044		61,923	10,513,210		61,923		1,409,517		261,277
2045		107,936	10,621,146		107,936		1,442,458		294,218
2046		252,730	10,873,876		252,730		1,475,557	39,725	287,592
2047		219,722	11,093,598		219,722		1,475,557		287,592
2048		178,170	11,271,768		178,170		1,515,440		327,475
2049		52,436	11,324,204		52,436		1,555,323	23,256	344,102
2050		74,019	11,398,223		74,019		1,555,323		344,102
2051		141,008	11,539,231		141,008		1,578,738		367,517
2052		169,542	11,708,773		169,542		1,603,084	31,316	360,547
TOTALS	6,527,817	5,180,956		3,293,130	8,415,643			1,242,537	

1/ GROSS INITIAL PROJECT INVESTMENT, RETIREMENTS INCLUDED

2C

FY 2002

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

A	B	C	D	E	F	G	H	I	J
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION		
YEAR	APPROPRIATIONS		BONDS		APPROPRIATIONS		APPROPRIATIONS		IRRIGATION
ENDING	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 1/	TRANS	GEN	AMORTIZATION
SEPT 30									
2002				66,000		41,412			
2003				25,622		23,410		17,362	
2004				27,400		55,123			739
2005				15,389		125,713		1,443	
2006				1		118,652		7	
2007				45,000		61,481		229	2,931
2008				104,300					19
2009				79,820		40,415			7,709
2010				88,475		39,745		81	
2011				46,384		72,899		165	
2012						96,409		107	811
2013				152,800		108,940			49,796
2014				61,080		254,222		867	48,554
2015				147,000		138,328		44,125	54,101
2016				27,000		232,754		49,367	64,264
2017				74,732		247,765		116,054	62,246
2018						544,078		115,104	25,460
2019				6,000		275,456		142,972	67,001
2020				209,210		194,560		93,757	36,743
2021						355,906		201,374	16,826
2022						484,278		67,887	15,831
2023						495,781		116,334	9,663
2024						523,046		8,883	138,659
2025						197,923			152,524
2026						80,179		546	
2027						106,073		79,910	
2028						20,708		179,981	
2029						164,432			
2030						34,177			
2031						134,470		983	
2032						123,020		3,514	
2033						49,467		7,056	
2034						38,147			
2035						170,807			
2036						68,529		630	
2037						50,266		58,649	
2038						2,909		9,260	
2039						141,511			
2040						576			
2041						106,565			
2042						50,752		1,996	
2043						41,515		7,801	
2044						61,923			
2045						107,936			
2046						251,797		933	
2047						20,542		199,180	
2048						122,219		55,951	
2049						52,436			
2050						74,019			
2051						141,008			
2052						100,182		69,360	
TOTALS				1,176,213		7,044,461		1,651,868	753,877

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2002

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

PRINCIPAL COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS

A	B	C	D	E
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2002	267,522	6,581	10,395	
2003	306,329	6,967	10,948	
2004	297,117	7,380	11,547	
2005	271,126	7,819	12,204	
2006	303,909	8,279	12,903	
2007	334,062	8,466	13,661	
2008	362,107	9,234	14,460	
2009	373,083	9,831	15,328	
2010	390,977		15,801	
2011	447,733		16,741	
2012	518,637		17,772	
2013	256,168		18,888	
2014	274,401		16,087	
2015	307,002		13,628	
2016	315,952		12,358	
2017	282,241		13,006	
2018	131,337		13,681	
2019	28,138		14,390	
2020	30,133		15,149	
2021	32,270		15,943	
2022	34,557		13,856	
2023	37,008		14,970	
2024	39,631		15,789	
2025	42,441		1,529	
2026	45,450		1,000	
2027	48,673		1,000	
2028	52,124		1,000	
2029	55,819		1,000	
2030	59,777			
2031	64,015			
2032	68,554			
2033	73,414			
2034	78,619			
2035	84,193			
2036	90,163			
2037	96,555			
2038	103,401			
2039	110,732			
2040	118,583			
2041	126,990			
2042	135,994			
2043	145,636			
2044	155,962			
2045	167,019			
2046	178,861			
2047	191,542			
2048	205,122			
2049	219,666			
TOTALS	8,360,745	64,557	335,034	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2002

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)

INTEREST PAYMENTS

A	B	C	D	E	F	G	H	I
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION	
YEAR	APPROPRIATIONS		BONDS 1/		APPROPRIATIONS		APPROPRIATIONS	
ENDING	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 2/	TRANS	GEN
SEPT 30								
2002				63,472		212,549		39,454
2003				63,579		213,656		39,509
2004				61,545		211,974		38,328
2005				58,930		208,188		38,328
2006				57,888		199,447		38,232
2007				58,703		191,152		38,232
2008				55,949		186,861		38,215
2009				49,846		186,861		38,215
2010				47,559		184,008		38,215
2011				38,616		188,801		38,210
2012				35,151		192,199		38,199
2013				26,740		189,822		39,966
2014				17,073		187,513		41,740
2015				12,833		177,040		41,677
2016				1,345		176,499		38,526
2017				-3,200		167,234		36,504
2018				-14,102		156,719		35,893
2019				-7,153		123,241		33,849
2020				-174		104,895		23,628
2021				-23,065		97,258		17,259
2022				-23,048		84,695		6,337
2023				-23,040		60,416		5,683
2024				-23,507		30,684		537
2025				-23,537		5,957		
2026				-23,557		2,341		17
2027				-23,557		3,218		2,460
2028				-23,557		637		5,546
2029				-23,557		5,005		
2030				-23,591		1,031		
2031				-23,591		3,977		30
2032				-23,591		3,668		108
2033				-23,591		1,518		218
2034				-23,591		1,159		
2035				-23,591		5,170		
2036				-23,591		1,988		20
2037				-23,591		1,518		1,814
2038				-23,591		88		282
2039				-23,591		4,252		
2040				-23,591		18		
2041				-23,591		3,163		
2042				-23,591		1,513		61
2043				-23,591		1,272		241
2044				-23,591		1,864		
2045				-23,591		3,234		
2046				-23,591		7,535		29
2047				-23,591		605		6,140
2048				-23,591		3,770		1,730
2049				-23,591		1,600		
2050				-23,591		2,260		
2051				-23,591		4,178		
2052				-23,591		3,054		2,139
TOTALS				-128,422		3,807,305		765,571

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ NET OF INTEREST INCOME AND AFUDC
2/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2002

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

A	B	C	D	E
	INTEREST COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS			
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2002	261,343	3,367	14,825	
2003	259,501	5,986	14,270	
2004	260,363	2,584	13,471	
2005	234,090	2,171	13,027	
2006	235,896	1,730	12,333	
2007	223,395	1,247	11,578	
2008	207,503	725	10,766	
2009	189,486	-10,330	9,877	
2010	169,758		8,954	
2011	132,598		7,992	
2012	81,686		9,171	
2013	105,470		4,020	
2014	81,241		7,362	
2015	47,942		6,465	
2016	31,056		5,766	
2017	-11,570		5,127	
2018	-22,482		4,451	
2019	281,252		3,735	
2020	279,257		2,981	
2021	277,121		-752	
2022	274,833		1,834	
2023	272,383		943	
2024	269,759		-13,341	
2025	266,949		27	
2026	263,940			
2027	260,718			
2028	257,267			
2029	253,571			
2030	249,614			
2031	245,375			
2032	240,837			
2033	235,976			
2034	230,771			
2035	225,197			
2036	219,228			
2037	212,835			
2038	205,990			
2039	198,658			
2040	190,808			
2041	182,400			
2042	173,396			
2043	163,754			
2044	153,429			
2045	142,371			
2046	130,529			
2047	117,848			
2048	104,268			
2049	89,725			
TOTALS	9,157,335	7,480	154,882	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2002

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
SUMMARY TOTALS

A	B	C	D	E	F	G	H	I
FISCAL YEAR ENDING SEPT 30	PRINCIPAL 1/ TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT	INTEREST TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT
2002		107,412	284,498	391,910		315,475	279,535	595,010
2003		66,394	324,244	390,638		316,744	279,757	596,501
2004		83,262	316,044	399,306		311,847	276,418	588,265
2005		142,545	291,149	433,694		305,446	249,288	554,734
2006		118,660	325,091	443,751		295,567	249,959	545,526
2007		109,641	356,189	465,830		288,087	236,220	524,307
2008		104,319	385,801	490,120		281,025	218,994	500,019
2009		127,944	398,242	526,186		274,922	189,033	463,955
2010		128,301	406,778	535,079		269,782	178,712	448,494
2011		119,448	464,474	583,922		265,627	140,590	406,217
2012		97,327	536,409	633,736		265,549	90,857	356,406
2013		311,536	275,056	586,592		256,528	109,490	366,018
2014		364,723	290,488	655,211		246,326	88,603	334,929
2015		383,554	320,630	704,184		231,550	54,407	285,957
2016		373,385	328,310	701,695		216,370	36,822	253,192
2017		500,797	295,247	796,044		200,538	-6,443	194,095
2018		684,642	145,018	829,660		178,510	-18,031	160,479
2019		491,429	42,528	533,957		149,937	284,987	434,924
2020		534,270	45,282	579,552		128,349	282,238	410,587
2021		574,106	48,213	622,319		91,452	276,369	367,821
2022		567,996	48,413	616,409		67,984	276,667	344,651
2023		621,778	51,978	673,756		43,059	273,326	316,385
2024		670,588	55,420	726,008		7,714	256,418	264,132
2025		350,447	43,970	394,417		-17,580	266,976	249,396
2026		80,725	46,450	127,175		-21,199	263,940	242,741
2027		185,983	49,673	235,656		-17,879	260,718	242,839
2028		200,689	53,124	253,813		-17,374	257,267	239,893
2029		164,432	56,819	221,251		-18,552	253,571	235,019
2030		34,177	59,777	93,954		-22,560	249,614	227,054
2031		135,453	64,015	199,468		-19,584	245,375	225,791
2032		126,534	68,554	195,088		-19,815	240,837	221,022
2033		56,523	73,414	129,937		-21,855	235,976	214,121
2034		38,147	78,619	116,766		-22,432	230,771	208,339
2035		170,807	84,193	255,000		-18,421	225,197	206,776
2036		69,159	90,163	159,322		-21,583	219,228	197,645
2037		108,915	96,555	205,470		-20,259	212,835	192,576
2038		12,169	103,401	115,570		-23,221	205,990	182,769
2039		141,511	110,732	252,243		-19,339	198,658	179,319
2040		576	118,583	119,159		-23,573	190,808	167,235
2041		106,565	126,990	233,555		-20,428	182,400	161,972
2042		52,748	135,994	188,742		-22,017	173,396	151,379
2043		49,316	145,636	194,952		-22,078	163,754	141,676
2044		61,923	155,962	217,885		-21,727	153,429	131,702
2045		107,936	167,019	274,955		-20,357	142,371	122,014
2046		252,730	178,861	431,591		-16,027	130,529	114,502
2047		219,722	191,542	411,264		-16,846	117,848	101,002
2048		178,170	205,122	383,292		-18,091	104,268	86,177
2049		52,436	219,666	272,102		-21,991	89,725	67,734
2050		74,019		74,019		-21,331		-21,331
2051		141,008		141,008		-19,413		-19,413
2052		169,542		169,542		-18,398		-18,398
TOTALS		10,626,419	8,760,336	19,386,755		4,444,454	9,319,697	13,764,151

LEGEND

CCO = CAPITALIZED CONTRACT OBLIGATIONS
CONS = CONSERVATION
GEN = GENERATION
TRANS = TRANSMISSION

1/ INCLUDES PAYMENTS FOR THE IRRIGATION ASSISTANCE

FY 2002

FEDERAL COLUMBIA RIVER POWER SYSTEM
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)

A FISCAL YEAR ENDING SEPT 30	B GENERATION UNAMORTIZED INVESTMENT	C GENERATION TERM SCHEDULE	D TRANSMISSION UNAMORTIZED INVESTMENT	E TRANSMISSION TERM SCHEDULE
CUMULATIVE 1999	3,931,367	4,929,735		
2000	4,051,118	5,069,908		
2001	4,609,333	5,606,476		
2002	4,763,658	5,802,213		
2003	4,697,264	5,545,807		
2004	4,614,741	5,386,695		
2005	4,472,196	5,238,949		
2006	4,353,536	5,185,749		
2007	4,246,826	5,084,143		
2008	4,142,526	4,750,968		
2009	4,022,291	4,632,853		
2010	3,893,990	4,570,036		
2011	4,028,261	4,768,527		
2012	3,967,875	4,676,349		
2013	3,876,506	4,693,920		
2014	3,629,510	4,689,439		
2015	3,489,754	4,732,136		
2016	3,304,004	4,760,210		
2017	3,006,994	4,798,606		
2018	2,686,297	5,037,042		
2019	2,279,808	4,923,962		
2020	1,808,571	4,808,840		
2021	1,395,901	4,798,774		
2022	1,051,898	4,911,811		
2023	529,058	4,826,524		
2024		4,822,024		
2025		4,665,135		
2026		4,436,790		
2027		4,466,727		
2028		4,448,495		
2029		4,293,680		
2030		4,300,276		
2031		4,260,259		
2032		4,096,526		
2033		3,826,860		
2034		3,846,676		
2035		3,852,122		
2036		3,852,338		
2037		3,865,337		
2038		3,849,002		
2039		3,904,422		
2040		3,902,213		
2041		3,928,649		
2042		3,941,313		
2043		3,819,129		
2044		3,728,973		
2045		3,555,355		
2046		3,405,565		
2047		3,395,488		
2048		3,412,783		
2049		3,402,794		
2050		3,398,635		
2051		2,898,444		
2052		2,771,003		

FY 2003

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
GENERATION

A	B	C	D	E	F	G	H	I	J
	INVESTMENT PLACED IN SERVICE						IRRIGATION ASSISTANCE		
FISCAL YEAR ENDING SEPT 30	INITIAL 1/ PROJECT THRU 9-30 +	REPLACE- MENTS THRU 9-30 =	CUMULATIVE AMOUNT IN SERVICE -	AMORTI- ZATION 9-30 -	DISCRETIONARY AMORTIZATION =	UNAMORTIZED INVESTMENT	CUMULATIVE AMOUNT IN SERVICE -	AMORTI- ZATION =	UNAMORTIZED AMOUNT
CUMULATIVE 1999	5,443,896	179,484	5,623,380	1,692,013		3,931,367	770,437		770,437
2000	210,182		5,833,562	50,115		4,091,434	770,437		770,437
2001	612,002		6,445,564	19,474	3,432	4,680,530	770,437	16,560	753,877
2002	261,737		6,707,301	66,000	55,676	4,820,591	770,437		753,877
2003	207,568		6,914,869	46,062	26,890	4,955,207	770,437		753,877
2004			6,914,869	82,507	1	4,872,699	770,437	739	753,138
2005			6,914,869	103,173	39,338	4,730,188	770,437		753,138
2006			6,914,869	53,200	65,433	4,611,555	770,437		753,138
2007			6,914,869	61,671	45,000	4,504,884	770,437	2,949	750,189
2008			6,914,869	104,300	1	4,400,583	770,437	1	750,188
2009			6,914,869	118,115	2,094	4,280,374	770,437	7,709	742,479
2010			6,914,869	62,726	65,545	4,152,103	777,379	6,566	742,855
2011		260,483	7,175,352	43,569	75,869	4,293,148	777,379		742,855
2012		37,095	7,212,447	55,618	40,936	4,233,689	780,855	811	745,520
2013		174,913	7,387,360	152,907	108,798	4,146,897	800,648	87,326	677,987
2014		71,017	7,458,377	61,080	255,093	3,901,741	800,648	48,554	629,433
2015		194,752	7,653,129	147,000	182,534	3,766,959	805,755	54,101	580,439
2016		126,659	7,779,788	94,342	214,908	3,584,368	811,149	99,517	486,316
2017		145,316	7,925,104	88,941	349,620	3,291,123	811,149	62,246	424,070
2018		347,506	8,272,610	94,623	564,527	2,979,479	862,336	25,460	449,797
2019		18,417	8,291,027	6,184	416,531	2,575,181	873,238	88,259	372,440
2020		26,992	8,318,019	32,585	460,457	2,109,131	873,238	36,743	335,697
2021		148,463	8,466,482	71,689	483,766	1,702,139	912,445	16,826	358,078
2022		213,710	8,680,192	28,126	523,379	1,364,344	951,494	44,911	352,216
2023		91,652	8,771,844	1,595	609,208	845,193	951,494	9,663	342,553
2024		2,946	8,774,790	105	646,988	201,046	993,300	21,072	363,287
2025		203,199	8,977,989	56,304	347,941		1,013,337	296,877	86,447
2026		82,877	9,060,866		82,877		1,013,337	6,462	79,985
2027		190,942	9,251,808		190,942		1,045,565		112,213
2028		206,038	9,457,846		206,038		1,078,951	44,797	100,802
2029		168,814	9,626,660		168,814		1,078,951		100,802
2030		35,090	9,661,750		35,090		1,108,914		130,765
2031		139,063	9,800,813		139,063		1,138,877	44,797	115,931
2032		129,909	9,930,722		129,909		1,138,877		115,931
2033		58,032	9,988,754		58,032		1,179,301		156,355
2034		39,164	10,027,918		39,164		1,219,725	29,207	167,572
2035		175,358	10,203,276		175,358		1,219,725		167,572
2036		71,004	10,274,280		71,004		1,248,274		196,121
2037		111,819	10,386,099		111,819		1,276,982	29,310	195,519
2038		12,493	10,398,592		12,493		1,276,982		195,519
2039		145,279	10,543,871		145,279		1,306,293		224,830
2040		591	10,544,462		591		1,340,128	33,836	224,829
2041		109,408	10,653,870		109,408		1,340,128		224,829
2042		54,153	10,708,023		54,153		1,374,822		259,523
2043		50,633	10,758,656		50,633		1,409,517	32,941	261,277
2044		63,574	10,822,230		63,574		1,409,517		261,277
2045		110,813	10,933,043		110,813		1,442,458		294,218
2046		259,467	11,192,510		259,467		1,475,557	39,725	287,592
2047		225,579	11,418,089		225,579		1,475,557		287,592
2048		182,917	11,601,006		182,917		1,515,440		327,475
2049		53,834	11,654,840		53,834		1,555,323	23,256	344,102
2050		75,991	11,730,831		75,991		1,555,323		344,102
2051		144,766	11,875,597		144,766		1,578,738		367,517
2052		174,063	12,049,660		174,063		1,603,084	31,316	360,547
2053		191,195	12,240,855		191,195		1,603,084		360,547
TOTALS	6,735,385	5,505,470		3,394,024	8,846,831			1,242,537	

1/ GROSS INITIAL PROJECT INVESTMENT, RETIREMENTS INCLUDED

FY 2003

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

A	B	C	D	E	F	G	H	I	J
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION		
YEAR	APPROPRIATIONS		BONDS		APPROPRIATIONS		APPROPRIATIONS		IRRIGATION
ENDING	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 1/	TRANS	GEN	AMORTIZATION
SEPT 30									
2003				25,622		29,968		17,362	
2004				27,400		55,108			739
2005				15,290		125,778		1,443	
2006						118,626		7	
2007				45,000		61,442		229	2,949
2008				104,301					1
2009				79,794		40,415			7,709
2010				88,445		39,745		81	
2011				46,539		72,734		165	
2012						96,447		107	811
2013				152,800		108,798		107	49,796
2014				61,080		254,226		867	48,554
2015				147,000		173,217		9,317	54,101
2016				27,000		247,442		34,808	64,264
2017				74,732		213,363		150,466	62,246
2018				38,317		489,813		131,020	25,460
2019				6,000		297,376		119,339	67,001
2020				271,186		140,922		80,934	36,743
2021				26,074		524,661		4,720	16,826
2022						489,897		61,608	15,831
2023						362,219		248,584	9,663
2024						519,129		127,964	21,072
2025						404,245			263,649
2026						82,316		561	6,462
2027						108,900		82,042	
2028						21,260		184,778	
2029						168,814			
2030						35,090			
2031						138,054		1,009	
2032						126,300		3,609	
2033						50,787		7,245	
2034						39,164			
2035						175,358			
2036						70,357		647	
2037						51,606		60,213	
2038						2,987		9,506	
2039						145,279			
2040						591			
2041						109,408			
2042						52,104		2,049	
2043						42,624		8,009	
2044						63,574			
2045						110,813			
2046						258,510		957	
2047						21,090		204,489	
2048						125,475		57,442	
2049						53,834			
2050						75,991			
2051						144,766			
2052						102,853		71,210	
2053						78,236		112,959	
TOTALS				1,236,580		7,321,712		1,795,853	753,877

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2003

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

PRINCIPAL COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS

A	B	C	D	E
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2003	306,329	6,967	10,948	
2004	297,117	7,380	11,547	
2005	271,126	7,819	12,204	
2006	303,909	8,279	12,903	
2007	334,062	8,466	13,661	
2008	362,107	9,234	14,460	
2009	373,083	9,831	15,328	
2010	390,977		15,801	
2011	447,733		16,741	
2012	518,637		17,772	
2013	256,168		18,888	
2014	274,401		16,087	
2015	307,002		13,628	
2016	315,952		12,358	
2017	282,241		13,006	
2018	131,337		13,681	
2019	30,183		14,390	
2020	32,262		15,149	
2021	34,485		15,943	
2022	36,861		13,856	
2023	39,401		14,970	
2024	42,116		15,789	
2025	45,018		1,529	
2026	48,119		1,000	
2027	51,435		1,000	
2028	54,979		1,000	
2029	58,767		1,000	
2030	62,816			
2031	67,144			
2032	71,770			
2033	76,715			
2034	82,001			
2035	87,650			
2036	93,689			
2037	100,145			
2038	107,045			
2039	114,420			
2040	122,304			
2041	130,730			
2042	139,738			
2043	149,366			
2044	159,657			
2045	170,657			
2046	182,415			
2047	194,984			
TOTALS	7,759,053	57,976	324,639	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2003

F E D E R A L C O L U M B I A R I V E R P O W E R S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

A	B	C	D	E	F	G	H	I
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION	
YEAR	APPROPRIATIONS		BONDS 1/		APPROPRIATIONS		APPROPRIATIONS	
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 2/	TRANS	GEN
2003				67,274		220,173		39,562
2004				69,854		220,396		38,435
2005				67,260		216,608		38,435
2006				66,215		207,863		38,339
2007				67,022		199,570		38,339
2008				64,262		195,281		38,322
2009				58,168		195,281		38,322
2010				55,885		192,428		38,322
2011				46,949		197,194		38,317
2012				43,451		200,577		38,306
2013				35,163		198,159		40,064
2014				25,500		195,823		41,822
2015				21,264		185,269		41,759
2016				9,784		182,180		41,100
2017				5,277		171,965		40,109
2018				-5,542		163,908		36,999
2019				-1,177		134,398		33,787
2020				8,459		114,479		25,254
2021				-20,349		109,515		19,469
2022				-23,236		86,548		20,690
2023				-23,229		62,441		20,517
2024				-23,688		41,559		7,624
2025				-23,719		17,149		
2026				-23,738		2,337		17
2027				-23,738		3,203		2,447
2028				-23,738		633		5,518
2029				-23,738		4,978		
2030				-23,772		1,027		
2031				-23,772		3,964		30
2032				-23,772		3,656		107
2033				-23,772		1,510		217
2034				-23,772		1,151		
2035				-23,772		5,138		
2036				-23,772		1,987		20
2037				-23,772		1,513		1,804
2038				-23,772		87		280
2039				-23,772		4,232		
2040				-23,772		18		
2041				-23,772		3,156		
2042				-23,772		1,506		61
2043				-23,772		1,266		240
2044				-23,772		1,853		
2045				-23,772		3,213		
2046				-23,772		7,507		29
2047				-23,772		605		6,109
2048				-23,772		3,751		1,721
2049				-23,772		1,591		
2050				-23,772		2,248		
2051				-23,772		4,163		
2052				-23,772		3,039		2,127
2053				-23,772		2,246		3,365
TOTALS				-74,633		3,780,342		777,985

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ NET OF INTEREST INCOME AND AFUDC
2/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2003

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

INTEREST COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS

A	B	C	D	E
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2003	259,501	5,986	14,270	
2004	260,363	2,584	13,471	
2005	234,090	2,171	13,027	
2006	235,896	1,730	12,333	
2007	223,395	1,247	11,578	
2008	207,503	725	10,766	
2009	189,486	-10,330	9,877	
2010	169,758		8,954	
2011	132,598		7,992	
2012	81,686		9,171	
2013	105,470		4,020	
2014	81,241		7,362	
2015	47,942		6,465	
2016	31,056		5,766	
2017	-11,570		5,127	
2018	-22,482		4,451	
2019	280,672		3,735	
2020	278,593		2,981	
2021	276,370		-752	
2022	273,994		1,834	
2023	271,454		943	
2024	268,739		-13,341	
2025	265,838		27	
2026	262,736			
2027	259,420			
2028	255,877			
2029	252,089			
2030	248,040			
2031	243,712			
2032	239,085			
2033	234,140			
2034	228,855			
2035	223,205			
2036	217,166			
2037	210,711			
2038	203,811			
2039	196,435			
2040	188,552			
2041	180,125			
2042	171,118			
2043	161,490			
2044	151,198			
2045	140,198			
2046	128,440			
2047	115,871			
TOTALS	8,653,867	4,113	140,057	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

2G

FY 2003

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
SUMMARY TOTALS

A	B	C	D	E	F	G	H	I
FISCAL	PRINCIPAL 1/				INTEREST			
YEAR ENDING SEPT 30	TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT	TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT
2003		72,952	324,244	397,196		327,009	279,757	606,766
2004		83,247	316,044	399,291		328,685	276,418	605,103
2005		142,511	291,149	433,660		322,303	249,288	571,591
2006		118,633	325,091	443,724		312,417	249,959	562,376
2007		109,620	356,189	465,809		304,931	236,220	541,151
2008		104,302	385,801	490,103		297,865	218,994	516,859
2009		127,918	398,242	526,160		291,771	189,033	480,804
2010		128,271	406,778	535,049		286,635	178,712	465,347
2011		119,438	464,474	583,912		282,460	140,590	423,050
2012		97,365	536,409	633,774		282,334	90,857	373,191
2013		311,501	275,056	586,557		273,386	109,490	382,876
2014		364,727	290,488	655,215		263,145	88,603	351,748
2015		383,635	320,630	704,265		248,292	54,407	302,699
2016		373,514	328,310	701,824		233,064	36,822	269,886
2017		500,807	295,247	796,054		217,351	-6,443	210,908
2018		684,610	145,018	829,628		195,365	-18,031	177,334
2019		489,716	44,573	534,289		167,008	284,407	451,415
2020		529,785	47,411	577,196		148,192	281,574	429,766
2021		572,281	50,428	622,709		108,635	275,618	384,253
2022		567,336	50,717	618,053		84,002	275,828	359,830
2023		620,466	54,371	674,837		59,729	272,397	332,126
2024		668,165	57,905	726,070		25,495	255,398	280,893
2025		667,894	46,547	714,441		-6,570	265,865	259,295
2026		89,339	49,119	138,458		-21,384	262,736	241,352
2027		190,942	52,435	243,377		-18,088	259,420	241,332
2028		206,038	55,979	262,017		-17,587	255,877	238,290
2029		168,814	59,767	228,581		-18,760	252,089	233,329
2030		35,090	62,816	97,906		-22,745	248,040	225,295
2031		139,063	67,144	206,207		-19,778	243,712	223,934
2032		129,909	71,770	201,679		-20,009	239,085	219,076
2033		58,032	76,715	134,747		-22,045	234,140	212,095
2034		39,164	82,001	121,165		-22,621	228,855	206,234
2035		175,358	87,650	263,008		-18,634	223,205	204,571
2036		71,004	93,689	164,693		-21,765	217,166	195,401
2037		111,819	100,145	211,964		-20,455	210,711	190,256
2038		12,493	107,045	119,538		-23,405	203,811	180,406
2039		145,279	114,420	259,699		-19,540	196,435	176,895
2040		591	122,304	122,895		-23,754	188,552	164,798
2041		109,408	130,730	240,138		-20,616	180,125	159,509
2042		54,153	139,738	193,891		-22,205	171,118	148,913
2043		50,633	149,366	199,999		-22,266	161,490	139,224
2044		63,574	159,657	223,231		-21,919	151,198	129,279
2045		110,813	170,657	281,470		-20,559	140,198	119,639
2046		259,467	182,415	441,882		-16,236	128,440	112,204
2047		225,579	194,984	420,563		-17,058	115,871	98,813
2048		182,917		182,917		-18,300		-18,300
2049		53,834		53,834		-22,181		-22,181
2050		75,991		75,991		-21,524		-21,524
2051		144,766		144,766		-19,609		-19,609
2052		174,063		174,063		-18,606		-18,606
2053		191,195		191,195		-18,161		-18,161
TOTALS		11,108,022	8,141,668	19,249,690		4,483,694	8,798,037	13,281,731

LEGEND

CCO = CAPITALIZED CONTRACT OBLIGATIONS
CONS = CONSERVATION
GEN = GENERATION
TRANS = TRANSMISSION

1/ INCLUDES PAYMENTS FOR THE IRRIGATION ASSISTANCE

FY 2003

FEDERAL COLUMBIA RIVER POWER SYSTEM
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)

A FISCAL YEAR ENDING SEPT 30	B GENERATION UNAMORTIZED INVESTMENT	C GENERATION TERM SCHEDULE	D TRANSMISSION UNAMORTIZED INVESTMENT	E TRANSMISSION TERM SCHEDULE
CUMULATIVE 1999	3,931,367	4,929,735		
2000	4,091,434	5,069,908		
2001	4,680,530	5,606,476		
2002	4,820,591	5,802,213		
2003	4,955,207	5,753,375		
2004	4,872,699	5,594,263		
2005	4,730,188	5,446,517		
2006	4,611,555	5,393,317		
2007	4,504,884	5,291,711		
2008	4,400,583	4,958,536		
2009	4,280,374	4,840,421		
2010	4,152,103	4,777,604		
2011	4,293,148	4,982,859		
2012	4,233,689	4,891,646		
2013	4,146,897	4,913,652		
2014	3,901,741	4,911,015		
2015	3,766,959	4,958,767		
2016	3,584,368	4,988,380		
2017	3,291,123	5,030,182		
2018	2,979,479	5,237,860		
2019	2,575,181	5,125,253		
2020	2,109,131	5,010,831		
2021	1,702,139	5,002,757		
2022	1,364,344	5,120,612		
2023	845,193	5,037,662		
2024	201,046	5,033,235		
2025		4,878,547		
2026		4,650,410		
2027		4,684,121		
2028		4,670,657		
2029		4,518,617		
2030		4,525,473		
2031		4,485,519		
2032		4,322,929		
2033		4,054,436		
2034		4,074,781		
2035		4,081,657		
2036		4,081,886		
2037		4,097,164		
2038		4,080,896		
2039		4,137,792		
2040		4,135,597		
2041		4,162,972		
2042		4,175,996		
2043		4,054,753		
2044		3,964,770		
2045		3,791,594		
2046		3,641,825		
2047		3,635,799		
2048		3,565,505		
2049		3,555,801		
2050		3,552,892		
2051		3,052,701		
2052		2,925,447		
2053		2,893,028		

FY 2004

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
GENERATION

A	B	C	D	E	F	G	H	I	J
	INVESTMENT PLACED IN SERVICE						IRRIGATION ASSISTANCE		
FISCAL YEAR ENDING SEPT 30	INITIAL 1/ PROJECT THRU 9-30 +	REPLACE- MENTS THRU 9-30 =	CUMULATIVE AMOUNT IN SERVICE -	AMORTI- ZATION 9-30 -	DISCRETIONARY= AMORTIZATION	UNAMORTIZED INVESTMENT	CUMULATIVE AMOUNT IN SERVICE -	AMORTI- = ZATION	UNAMORTIZED AMOUNT
CUMULATIVE 1999	5,443,896	179,484	5,623,380	1,692,013		3,931,367	770,437		770,437
2000	210,182		5,833,562	50,115		4,091,434	770,437		770,437
2001	612,002		6,445,564	19,474	3,432	4,680,530	770,437	16,560	753,877
2002	261,737		6,707,301	66,000	55,676	4,820,591	770,437		753,877
2003	207,568		6,914,869	46,062	9,975	4,972,122	770,437		753,877
2004	333,432		7,248,301	83,864	8,383	5,213,307	770,437	739	753,138
2005			7,248,301	103,173	39,341	5,070,793	770,437		753,138
2006			7,248,301	53,200	65,436	4,952,157	770,437		753,138
2007			7,248,301	61,679	45,000	4,845,478	770,437	2,945	750,193
2008			7,248,301	104,300		4,741,178	770,437	5	750,188
2009			7,248,301	118,115	2,097	4,620,966	770,437	7,709	742,479
2010			7,248,301	62,726	65,549	4,492,691	777,379	6,566	742,855
2011		267,681	7,515,982	43,569	75,682	4,641,121	777,379		742,855
2012		38,118	7,554,100	55,618	40,509	4,583,112	780,855	811	745,520
2013		179,747	7,733,847	152,907	108,174	4,501,778	800,648	87,326	677,987
2014		72,982	7,806,829	61,187	254,122	4,259,451	800,648	48,554	629,433
2015		200,134	8,006,963	147,000	181,418	4,131,167	805,755	54,101	580,439
2016		130,160	8,137,123	96,203	211,616	3,953,508	811,149	99,517	486,316
2017		149,329	8,286,452	89,333	347,441	3,666,063	811,149	62,246	424,070
2018		357,112	8,643,564	96,181	560,650	3,366,344	862,336	25,460	449,797
2019		18,925	8,662,489	42,014	368,810	2,974,445	873,238	88,259	372,440
2020		27,737	8,690,226	32,586	450,748	2,518,848	873,238	36,743	335,697
2021		152,566	8,842,792	74,670	461,210	2,135,534	912,445	16,826	358,078
2022		219,615	9,062,407	28,902	508,559	1,817,688	951,494	44,911	352,216
2023		94,188	9,156,595	1,640	594,330	1,315,906	951,494	9,663	342,553
2024		3,029	9,159,624	109	631,205	687,621	993,300	21,072	363,287
2025		208,815	9,368,439	121,670	511,801	262,965	1,013,337	51,516	331,808
2026		85,168	9,453,607	76,727	271,406		1,013,337	251,823	79,985
2027		196,217	9,649,824		196,217		1,045,565		112,213
2028		211,731	9,861,555		211,731		1,078,951	44,797	100,802
2029		173,479	10,035,034		173,479		1,078,951		100,802
2030		36,058	10,071,092		36,058		1,108,914		130,765
2031		142,908	10,214,000		142,908		1,138,877	44,797	115,931
2032		133,499	10,347,499		133,499		1,138,877		115,931
2033		59,635	10,407,134		59,635		1,179,301		156,355
2034		40,248	10,447,382		40,248		1,219,725	29,207	167,572
2035		180,203	10,627,585		180,203		1,219,725		167,572
2036		72,965	10,700,550		72,965		1,248,274		196,121
2037		114,907	10,815,457		114,907		1,276,982	29,310	195,519
2038		12,841	10,828,298		12,841		1,276,982		195,519
2039		149,299	10,977,597		149,299		1,306,293		224,830
2040		607	10,978,204		607		1,340,128	33,836	224,829
2041		112,431	11,090,635		112,431		1,340,128		224,829
2042		55,650	11,146,285		55,650		1,374,822		259,523
2043		52,030	11,198,315		52,030		1,409,517	32,941	261,277
2044		65,332	11,263,647		65,332		1,409,517		261,277
2045		113,876	11,377,523		113,876		1,442,458		294,218
2046		266,638	11,644,161		266,638		1,475,557	39,725	287,592
2047		231,811	11,875,972		231,811		1,475,557		287,592
2048		187,976	12,063,948		187,976		1,515,440		327,475
2049		55,321	12,119,269		55,321		1,555,323	23,256	344,102
2050		78,091	12,197,360		78,091		1,555,323		344,102
2051		148,765	12,346,125		148,765		1,578,738		367,517
2052		178,873	12,524,998		178,873		1,603,084	31,316	360,547
2053		196,480	12,721,478		196,480		1,603,084		360,547
2054		5,809	12,727,287		5,809		1,634,400		391,863
TOTALS	7,068,817	5,658,470		3,581,037	9,146,250			1,242,537	

1/ GROSS INITIAL PROJECT INVESTMENT, RETIREMENTS INCLUDED

FY 2004

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

A	B	C	D	E	F	G	H	I	J
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION		
YEAR	APPROPRIATIONS		BONDS		APPROPRIATIONS		APPROPRIATIONS		IRRIGATION
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 1/	TRANS	GEN	AMORTIZATION
2004				27,400		64,847			739
2005				15,304		125,767		1,443	
2006						118,629		7	
2007				45,000		61,450		229	2,945
2008				104,300					5
2009				79,797		40,415			7,709
2010				88,449		39,745		81	
2011				46,519		72,567		165	
2012						96,020		107	811
2013				152,800		108,174		107	49,796
2014				61,080		253,255		974	48,554
2015				147,000		181,418			54,101
2016				27,000		236,694		44,125	64,264
2017				74,732		219,472		142,570	62,246
2018				38,317		495,739		122,775	25,460
2019				41,825		233,519		135,480	67,001
2020				193,927		208,473		80,934	36,743
2021				166,433		364,727		4,720	16,826
2022						532,628		4,833	15,831
2023						462,745		133,225	9,663
2024						379,217		252,097	21,072
2025						571,837		61,634	18,288
2026						347,556		577	251,823
2027						111,909		84,308	
2028						21,847		189,884	
2029						173,479			
2030						36,058			
2031						141,871		1,037	
2032						129,791		3,708	
2033						52,190		7,445	
2034						40,248			
2035						180,203			
2036						72,300		665	
2037						53,030		61,877	
2038						3,070		9,771	
2039						149,299			
2040						607			
2041						112,431			
2042						53,544		2,106	
2043						43,799		8,231	
2044						65,332			
2045						113,876			
2046						265,654		984	
2047						21,671		210,140	
2048						128,946		59,030	
2049						55,321			
2050						78,091			
2051						148,765			
2052						105,696		73,177	
2053						80,399		116,081	
2054						5,809			
TOTALS				1,309,883		7,660,130		1,814,527	753,877

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2004

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

A	B	C	D	E
	PRINCIPAL COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS			
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2004	297,117	7,380	11,547	
2005	271,126	7,819	12,204	
2006	303,909	8,279	12,903	
2007	334,062	8,466	13,661	
2008	362,107	9,234	14,460	
2009	373,083	9,831	15,328	
2010	390,977		15,801	
2011	447,733		16,741	
2012	518,637		17,772	
2013	256,168		18,888	
2014	274,401		16,087	
2015	307,002		13,628	
2016	315,952		12,358	
2017	282,241		13,006	
2018	131,337		13,681	
2019	30,933		14,390	
2020	33,067		15,149	
2021	35,349		15,943	
2022	37,788		13,856	
2023	40,395		14,970	
2024	43,182		15,789	
2025	46,162		1,529	
2026	49,347		1,000	
2027	52,752		1,000	
2028	56,392		1,000	
2029	60,283		1,000	
2030	64,442			
2031	68,889			
2032	73,642			
2033	78,724			
2034	84,156			
2035	89,962			
2036	96,170			
2037	102,805			
2038	109,899			
2039	117,482			
2040	125,588			
2041	134,254			
2042	143,517			
2043	153,420			
2044	164,006			
2045	175,323			
2046	187,420			
2047	200,352			
TOTALS	7,521,553	51,009	313,691	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2004

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

A	B	C	D	E	F	G	H	I
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION	
YEAR	APPROPRIATIONS		BONDS 1/		APPROPRIATIONS		APPROPRIATIONS	
ENDING	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 2/	TRANS	GEN
SEPT 30								
2004				72,488		228,598		38,488
2005				73,331		231,094		38,542
2006				72,285		222,350		38,446
2007				73,092		214,056		38,446
2008				70,333		209,767		38,429
2009				64,239		209,767		38,429
2010				61,955		206,914		38,429
2011				53,016		211,874		38,424
2012				49,524		215,491		38,413
2013				41,227		213,229		40,221
2014				31,565		211,084		42,027
2015				27,328		200,790		41,957
2016				15,848		197,349		41,965
2017				11,339		188,117		40,349
2018				515		179,819		38,017
2019				5,185		150,046		35,568
2020				9,194		134,724		25,882
2021				-5,048		125,061		20,097
2022				-23,663		112,251		21,358
2023				-23,656		85,433		24,685
2024				-24,116		58,529		18,761
2025				-24,147		41,967		3,645
2026				-24,166		17,121		17
2027				-24,166		3,286		2,515
2028				-24,166		651		5,671
2029				-24,166		5,113		
2030				-24,200		1,052		
2031				-24,200		4,059		31
2032				-24,200		3,747		110
2033				-24,200		1,552		222
2034				-24,200		1,182		
2035				-24,200		5,269		
2036				-24,200		2,033		20
2037				-24,200		1,551		1,853
2038				-24,200		89		286
2039				-24,200		4,342		
2040				-24,200		18		
2041				-24,200		3,233		
2042				-24,200		1,544		62
2043				-24,200		1,302		246
2044				-24,200		1,902		
2045				-24,200		3,292		
2046				-24,200		7,697		30
2047				-24,200		618		6,279
2048				-24,200		3,857		1,770
2049				-24,200		1,633		
2050				-24,200		2,309		
2051				-24,200		4,264		
2052				-24,200		3,121		2,185
2053				-24,200		2,304		3,456
2054				-24,200		169		
TOTALS				-69,819		3,936,620		765,331

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ NET OF INTEREST INCOME AND AFUDC
2/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2004

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

A	B	C	D	E
	INTEREST COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS			
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2004	260,363	2,584	13,471	
2005	234,090	2,171	13,027	
2006	235,896	1,730	12,333	
2007	223,395	1,247	11,578	
2008	207,503	725	10,766	
2009	189,486	-10,330	9,877	
2010	169,758		8,954	
2011	132,598		7,992	
2012	81,686		9,171	
2013	105,470		4,020	
2014	81,241		7,362	
2015	47,942		6,465	
2016	31,056		5,766	
2017	-11,570		5,127	
2018	-22,482		4,451	
2019	288,690		3,735	
2020	286,555		2,981	
2021	284,274		-752	
2022	281,835		1,834	
2023	279,227		943	
2024	276,440		-13,341	
2025	273,461		27	
2026	270,275			
2027	266,870			
2028	263,231			
2029	259,339			
2030	255,180			
2031	250,733			
2032	245,980			
2033	240,899			
2034	235,467			
2035	229,660			
2036	223,453			
2037	216,817			
2038	209,723			
2039	202,140			
2040	194,034			
2041	185,368			
2042	176,105			
2043	166,202			
2044	155,616			
2045	144,300			
2046	132,203			
2047	119,271			
TOTALS	8,579,780	-1,873	125,787	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2004

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
SUMMARY TOTALS

A	B	C	D	E	F	G	H	I
FISCAL YEAR ENDING SEPT 30	PRINCIPAL 1/ TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT	INTEREST TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT
2004		92,986	316,044	409,030		339,574	276,418	615,992
2005		142,514	291,149	433,663		342,967	249,288	592,255
2006		118,636	325,091	443,727		333,081	249,959	583,040
2007		109,624	356,189	465,813		325,594	236,220	561,814
2008		104,305	385,801	490,106		318,529	218,994	537,523
2009		127,921	398,242	526,163		312,435	189,033	501,468
2010		128,275	406,778	535,053		307,298	178,712	486,010
2011		119,251	464,474	583,725		303,314	140,590	443,904
2012		96,938	536,409	633,347		303,428	90,857	394,285
2013		310,877	275,056	585,933		294,677	109,490	404,167
2014		363,863	290,488	654,351		284,676	88,603	373,279
2015		382,519	320,630	703,149		270,075	54,407	324,482
2016		372,083	328,310	700,393		255,162	36,822	291,984
2017		499,020	295,247	794,267		239,805	-6,443	233,362
2018		682,291	145,018	827,309		218,351	-18,031	200,320
2019		477,825	45,323	523,148		190,799	292,425	483,224
2020		520,077	48,216	568,293		169,800	289,536	459,336
2021		552,706	51,292	603,998		140,110	283,522	423,632
2022		553,292	51,644	604,936		109,946	283,669	393,615
2023		605,633	55,365	660,998		86,462	280,170	366,632
2024		652,386	58,971	711,357		53,174	263,099	316,273
2025		651,759	47,691	699,450		21,465	273,488	294,953
2026		599,956	50,347	650,303		-7,028	270,275	263,247
2027		196,217	53,752	249,969		-18,365	266,870	248,505
2028		211,731	57,392	269,123		-17,844	263,231	245,387
2029		173,479	61,283	234,762		-19,053	259,339	240,286
2030		36,058	64,442	100,500		-23,148	255,180	232,032
2031		142,908	68,889	211,797		-20,110	250,733	230,623
2032		133,499	73,642	207,141		-20,343	245,980	225,637
2033		59,635	78,724	138,359		-22,426	240,899	218,473
2034		40,248	84,156	124,404		-23,018	235,467	212,449
2035		180,203	89,962	270,165		-18,931	229,660	210,729
2036		72,965	96,170	169,135		-22,147	223,453	201,306
2037		114,907	102,805	217,712		-20,796	216,817	196,021
2038		12,841	109,899	122,740		-23,825	209,723	185,898
2039		149,299	117,482	266,781		-19,858	202,140	182,282
2040		607	125,588	126,195		-24,182	194,034	169,852
2041		112,431	134,254	246,685		-20,967	185,368	164,401
2042		55,650	143,517	199,167		-22,594	176,105	153,511
2043		52,030	153,420	205,450		-22,652	166,202	143,550
2044		65,332	164,006	229,338		-22,298	155,616	133,318
2045		113,876	175,323	289,199		-20,908	144,300	123,392
2046		266,638	187,420	454,058		-16,473	132,203	115,730
2047		231,811	200,352	432,163		-17,303	119,271	101,968
2048		187,976		187,976		-18,573		-18,573
2049		55,321		55,321		-22,567		-22,567
2050		78,091		78,091		-21,891		-21,891
2051		148,765		148,765		-19,936		-19,936
2052		178,873		178,873		-18,894		-18,894
2053		196,480		196,480		-18,440		-18,440
2054		5,809		5,809		-24,031		-24,031
TOTALS		11,538,417	7,886,253	19,424,670		4,632,132	8,703,694	13,335,826

LEGEND

CCO   = CAPITALIZED CONTRACT OBLIGATIONS
CONS = CONSERVATION
GEN   = GENERATION
TRANS = TRANSMISSION

1/ INCLUDES PAYMENTS FOR THE IRRIGATION ASSISTANCE

FY 2004

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)

A FISCAL YEAR ENDING SEPT 30	B GENERATION UNAMORTIZED INVESTMENT	C TERM SCHEDULE	D TRANSMISSION UNAMORTIZED INVESTMENT	E TERM SCHEDULE
CUMULATIVE 1999	3,931,367	4,929,735		
2000	4,091,434	5,069,908		
2001	4,680,530	5,606,476		
2002	4,820,591	5,802,213		
2003	4,972,122	5,753,375		
2004	5,213,307	5,927,695		
2005	5,070,793	5,779,949		
2006	4,952,157	5,726,749		
2007	4,845,478	5,625,143		
2008	4,741,178	5,291,968		
2009	4,620,966	5,173,853		
2010	4,492,691	5,111,036		
2011	4,641,121	5,323,489		
2012	4,583,112	5,233,299		
2013	4,501,778	5,260,139		
2014	4,259,451	5,259,360		
2015	4,131,167	5,312,494		
2016	3,953,508	5,343,747		
2017	3,666,063	5,389,170		
2018	3,366,344	5,604,896		
2019	2,974,445	5,456,967		
2020	2,518,848	5,343,289		
2021	2,135,534	5,337,337		
2022	1,817,688	5,460,321		
2023	1,315,906	5,379,862		
2024	687,621	5,375,514		
2025	262,965	5,223,169		
2026		4,995,255		
2027		5,032,982		
2028		5,025,134		
2029		4,875,541		
2030		4,882,671		
2031		4,842,783		
2032		4,681,408		
2033		4,414,163		
2034		4,435,071		
2035		4,443,469		
2036		4,443,712		
2037		4,461,417		
2038		4,445,221		
2039		4,503,690		
2040		4,501,511		
2041		4,529,884		
2042		4,543,292		
2043		4,423,051		
2044		4,333,253		
2045		4,160,548		
2046		4,010,801		
2047		4,009,088		
2048		3,939,285		
2049		3,866,784		
2050		3,865,207		
2051		3,365,016		
2052		3,237,960		
2053		3,206,873		

FY 2005

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
GENERATION

A	B	C	D	E	F	G	H	I	J
	INVESTMENT PLACED IN SERVICE						IRRIGATION ASSISTANCE		
FISCAL YEAR ENDING SEPT 30	INITIAL 1/ PROJECT THRU 9-30 +	REPLACE-MENTS THRU 9-30 =	CUMULATIVE AMOUNT IN SERVICE -	AMORTI-ZATION 9-30 -	DISCRETIONARY AMORTIZATION =	UNAMORTIZED INVESTMENT	CUMULATIVE AMOUNT IN SERVICE -	AMORTI-ZATION =	UNAMORTIZED AMOUNT
CUMULATIVE 1999	5,443,896	179,484	5,623,380	1,692,013		3,931,367	770,437		770,437
2000	210,182		5,833,562	50,115		4,091,434	770,437		770,437
2001	612,002		6,445,564	19,474	3,432	4,680,530	770,437	16,560	753,877
2002	261,737		6,707,301	66,000	55,676	4,820,591	770,437		753,877
2003	207,568		6,914,869	46,062	9,944	4,972,153	770,437		753,877
2004	333,432		7,248,301	67,086	6	5,238,493	770,437	739	753,138
2005	219,995		7,468,296	103,173	45,586	5,309,729	770,437		753,138
2006			7,468,296	53,200	65,453	5,191,076	770,437		753,138
2007			7,468,296	61,307	45,325	5,084,444	770,437	2,950	750,188
2008			7,468,296	104,300	42	4,980,102	770,437		750,188
2009			7,468,296	118,115	2,139	4,859,848	770,437	7,709	742,479
2010			7,468,296	62,726	65,593	4,731,529	777,379	6,566	742,855
2011		218,159	7,686,455	43,569	77,565	4,828,554	777,379		742,855
2012		31,067	7,717,522	55,618	43,835	4,760,168	780,855	811	745,520
2013		146,493	7,864,015	152,907	112,948	4,640,806	800,648	87,326	677,987
2014		59,479	7,923,494	66,697	255,154	4,378,434	800,648	48,554	629,433
2015		163,109	8,086,603	147,107	189,839	4,204,597	805,755	54,101	580,439
2016		106,079	8,192,682	83,400	235,383	3,991,893	811,149	99,517	486,316
2017		121,704	8,314,386	86,632	363,606	3,663,359	811,149	62,246	424,070
2018		291,043	8,605,429	85,474	588,637	3,280,291	862,336	25,460	449,797
2019		15,425	8,620,854	41,979	381,622	2,872,115	873,238	88,259	372,440
2020		22,606	8,643,460	66,568	427,936	2,400,217	873,238	36,743	335,697
2021		124,341	8,767,801	60,041	491,182	1,973,335	912,445	16,826	358,078
2022		178,987	8,946,788	23,556	532,399	1,596,367	951,494	44,911	352,216
2023		76,763	9,023,551	1,337	615,932	1,055,861	951,494	9,663	342,553
2024		2,469	9,026,020	89	654,280	403,961	993,300	21,072	363,287
2025		170,182	9,196,202	99,159	474,984		1,013,337	136,204	247,120
2026		69,411	9,265,613		69,411		1,013,337	167,135	79,985
2027		159,917	9,425,530		159,917		1,045,565		112,213
2028		172,560	9,598,090		172,560		1,078,951	44,797	100,802
2029		141,385	9,739,475		141,385		1,078,951		100,802
2030		29,387	9,768,862		29,387		1,108,914		130,765
2031		116,469	9,885,331		116,469		1,138,877	44,797	115,931
2032		108,800	9,994,131		108,800		1,138,877		115,931
2033		48,603	10,042,734		48,603		1,179,301		156,355
2034		32,801	10,075,535		32,801		1,219,725	29,207	167,572
2035		146,866	10,222,401		146,866		1,219,725		167,572
2036		59,466	10,281,867		59,466		1,248,274		196,121
2037		93,650	10,375,517		93,650		1,276,982	29,310	195,519
2038		10,464	10,385,981		10,464		1,276,982		195,519
2039		121,676	10,507,657		121,676		1,306,293		224,830
2040		495	10,508,152		495		1,340,128	33,836	224,829
2041		91,631	10,599,783		91,631		1,340,128		224,829
2042		45,354	10,645,137		45,354		1,374,822		259,523
2043		42,405	10,687,542		42,405		1,409,517	32,941	261,277
2044		53,245	10,740,787		53,245		1,409,517		261,277
2045		92,809	10,833,596		92,809		1,442,458		294,218
2046		217,308	11,050,904		217,308		1,475,557	39,725	287,592
2047		188,927	11,239,831		188,927		1,475,557		287,592
2048		153,199	11,393,030		153,199		1,515,440		327,475
2049		45,087	11,438,117		45,087		1,555,323	23,256	344,102
2050		63,644	11,501,761		63,644		1,555,323		344,102
2051		121,244	11,623,005		121,244		1,578,738		367,517
2052		145,781	11,768,786		145,781		1,603,084	31,316	360,547
2053		160,129	11,928,915		160,129		1,603,084		360,547
2054		4,734	11,933,649		4,734		1,634,400		391,863
2055		122,138	12,055,787		122,138		1,665,716	24,194	398,985
TOTALS	7,288,812	4,766,975		3,457,704	8,598,083			1,266,731	

1/ GROSS INITIAL PROJECT INVESTMENT, RETIREMENTS INCLUDED

FY 2005

FEDERAL COLUMBIA RIVER POWER SYSTEM

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

A	B	C	D	E	F	G	H	I	J
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION		
YEAR	APPROPRIATIONS		BONDS		APPROPRIATIONS		APPROPRIATIONS		IRRIGATION
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 1/	TRANS	GEN	AMORTIZATION
2005				20,878		126,438		1,443	
2006				316		118,330		7	
2007				45,325		61,078		229	2,950
2008				104,342					
2009				79,839		40,415			7,709
2010				88,493		39,745		81	
2011				40,176		80,793		165	
2012						99,346		107	811
2013				152,800		112,948		107	49,796
2014				61,080		259,797		974	48,554
2015				147,000		184,390		5,556	54,101
2016				27,000		239,591		52,192	64,264
2017				74,732		238,556		136,950	62,246
2018				38,317		490,392		145,402	25,460
2019				41,825		276,819		104,957	67,001
2020				291,937		121,633		80,934	36,743
2021				165,911		380,592		4,720	16,826
2022						551,122		4,833	15,831
2023						431,453		185,816	9,663
2024						476,280		178,089	21,072
2025						571,710		2,433	102,976
2026						68,941		470	167,135
2027						91,206		68,711	
2028						17,805		154,755	
2029						141,385			
2030						29,387			
2031						115,624		845	
2032						105,778		3,022	
2033						42,535		6,068	
2034						32,801			
2035						146,866			
2036						58,924		542	
2037						43,221		50,429	
2038						2,502		7,962	
2039						121,676			
2040						495			
2041						91,631			
2042						43,638		1,716	
2043						35,697		6,708	
2044						53,245			
2045						92,809			
2046						216,506		802	
2047						17,663		171,264	
2048						105,090		48,109	
2049						45,087			
2050						63,644			
2051						121,244			
2052						86,142		59,639	
2053						65,524		94,605	
2054						4,734			
2055						122,138			
TOTALS				1,379,971		7,085,366		1,580,642	753,138

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2005

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
PRINCIPAL PAYMENTS

PRINCIPAL COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS

A	B	C	D	E
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2005	271,126	7,819	12,204	
2006	303,909	8,279	12,903	
2007	334,062	8,466	13,661	
2008	362,107	9,234	14,460	
2009	373,083	9,831	15,328	
2010	390,977		15,801	
2011	447,733		16,741	
2012	518,637		17,772	
2013	256,168		18,888	
2014	274,401		16,087	
2015	307,002		13,628	
2016	315,952		12,358	
2017	282,241		13,006	
2018	131,337		13,681	
2019	31,886		14,390	
2020	34,080		15,149	
2021	36,425		15,943	
2022	38,931		13,856	
2023	41,610		14,970	
2024	44,472		15,789	
2025	47,532		1,529	
2026	50,802		1,000	
2027	54,297		1,000	
2028	58,033		1,000	
2029	62,026		1,000	
2030	66,293			
2031	70,854			
2032	75,729			
2033	80,939			
2034	86,507			
2035	92,459			
2036	98,820			
2037	105,619			
2038	112,886			
2039	120,652			
2040	128,953			
2041	137,825			
2042	147,308			
2043	157,442			
2044	168,274			
2045	179,852			
2046	192,225			
2047	205,451			
TOTALS	7,296,917	43,629	302,144	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2005

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

A	B	C	D	E	F	G	H	I
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION	
YEAR	APPROPRIATIONS		BONDS 1/		APPROPRIATIONS		APPROPRIATIONS	
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 2/	TRANS	GEN
2005				76,473		236,535		38,595
2006				78,040		231,353		38,552
2007				78,822		223,081		38,552
2008				76,020		218,818		38,535
2009				69,921		218,818		38,535
2010				67,635		215,965		38,535
2011				58,330		219,452		38,530
2012				55,684		220,780		38,519
2013				47,388		217,408		39,988
2014				37,725		213,833		41,457
2015				33,489		201,552		41,387
2016				22,008		196,075		40,996
2017				17,499		185,210		38,513
2018				6,675		174,161		35,116
2019				11,609		143,724		29,865
2020				18,395		125,049		22,362
2021				-5,234		120,600		16,577
2022				-23,909		104,993		17,544
2023				-23,901		76,047		20,193
2024				-24,361		50,903		10,753
2025				-24,392		27,534		139
2026				-24,411		1,932		14
2027				-24,411		2,667		2,045
2028				-24,411		530		4,609
2029				-24,411		4,147		
2030				-24,445		853		
2031				-24,445		3,283		25
2032				-24,445		3,034		89
2033				-24,445		1,261		181
2034				-24,445		960		
2035				-24,445		4,270		
2036				-24,445		1,641		15
2037				-24,445		1,260		1,507
2038				-24,445		73		233
2039				-24,445		3,520		
2040				-24,445		15		
2041				-24,445		2,619		
2042				-24,445		1,249		51
2043				-24,445		1,057		200
2044				-24,445		1,539		
2045				-24,445		2,665		
2046				-24,445		6,237		24
2047				-24,445		502		5,104
2048				-24,445		3,134		1,440
2049				-24,445		1,327		
2050				-24,445		1,874		
2051				-24,445		3,449		
2052				-24,445		2,534		1,776
2053				-24,445		1,865		2,809
2054				-24,445		139		
2055				-35,633		3,544		
TOTALS				-90,485		3,685,071		683,365

LEGEND

TRANS = TRANSMISSION
GEN   = GENERATION
CONS = CONSERVATION

1/ NET OF INTEREST INCOME AND AFUDC
2/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

FY 2005

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

INTEREST COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS

A	B	C	D	E
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2005	234,090	2,171	13,027	
2006	235,896	1,730	12,333	
2007	223,395	1,247	11,578	
2008	207,503	725	10,766	
2009	189,486	-10,330	9,877	
2010	169,758		8,954	
2011	132,598		7,992	
2012	81,686		9,171	
2013	105,470		4,020	
2014	81,241		7,362	
2015	47,942		6,465	
2016	31,056		5,766	
2017	-11,570		5,127	
2018	-22,482		4,451	
2019	295,441		3,735	
2020	293,247		2,981	
2021	290,902		-752	
2022	288,396		1,834	
2023	285,718		943	
2024	282,855		-13,341	
2025	279,795		27	
2026	276,525			
2027	273,030			
2028	269,294			
2029	265,302			
2030	261,034			
2031	256,473			
2032	251,599			
2033	246,389			
2034	240,820			
2035	234,868			
2036	228,507			
2037	221,708			
2038	214,442			
2039	206,675			
2040	198,374			
2041	189,502			
2042	180,020			
2043	169,885			
2044	159,053			
2045	147,476			
2046	135,102			
2047	121,877			
TOTALS	8,470,378	-4,457	112,316	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2005

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
SUMMARY TOTALS

A	B	C	D	E	F	G	H	I
FISCAL YEAR ENDING SEPT 30	PRINCIPAL 1/				INTEREST			
	TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT	TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT
2005		148,759	291,149	439,908		351,603	249,288	600,891
2006		118,653	325,091	443,744		347,945	249,959	597,904
2007		109,582	356,189	465,771		340,455	236,220	576,675
2008		104,342	385,801	490,143		333,373	218,994	552,367
2009		127,963	398,242	526,205		327,274	189,033	516,307
2010		128,319	406,778	535,097		322,135	178,712	500,847
2011		121,134	464,474	585,608		316,312	140,590	456,902
2012		100,264	536,409	636,673		314,983	90,857	405,840
2013		315,651	275,056	590,707		304,784	109,490	414,274
2014		370,405	290,488	660,893		293,015	88,603	381,618
2015		391,047	320,630	711,677		276,428	54,407	330,835
2016		383,047	328,310	711,357		259,079	36,822	295,901
2017		512,484	295,247	807,731		241,222	-6,443	234,779
2018		699,571	145,018	844,589		215,952	-18,031	197,921
2019		490,602	46,276	536,878		185,198	299,176	484,374
2020		531,247	49,229	580,476		165,806	296,228	462,034
2021		568,049	52,368	620,417		131,943	290,150	422,093
2022		571,786	52,787	624,573		98,628	290,230	388,858
2023		626,932	56,580	683,512		72,339	286,661	359,000
2024		675,441	60,261	735,702		37,295	269,514	306,809
2025		677,119	49,061	726,180		3,281	279,822	283,103
2026		236,546	51,802	288,348		-22,465	276,525	254,060
2027		159,917	55,297	215,214		-19,699	273,030	253,331
2028		172,560	59,033	231,593		-19,272	269,294	250,022
2029		141,385	63,026	204,411		-20,264	265,302	245,038
2030		29,387	66,293	95,680		-23,592	261,034	237,442
2031		116,469	70,854	187,323		-21,137	256,473	235,336
2032		108,800	75,729	184,529		-21,322	251,599	230,277
2033		48,603	80,939	129,542		-23,003	246,389	223,386
2034		32,801	86,507	119,308		-23,485	240,820	217,335
2035		146,866	92,459	239,325		-20,175	234,868	214,693
2036		59,466	98,820	158,286		-22,789	228,507	205,718
2037		93,650	105,619	199,269		-21,678	221,708	200,030
2038		10,464	112,886	123,350		-24,139	214,442	190,303
2039		121,676	120,652	242,328		-20,925	206,675	185,750
2040		495	128,953	129,448		-24,430	198,374	173,944
2041		91,631	137,825	229,456		-21,826	189,502	167,676
2042		45,354	147,308	192,662		-23,145	180,020	156,875
2043		42,405	157,442	199,847		-23,188	169,885	146,697
2044		53,245	168,274	221,519		-22,906	159,053	136,147
2045		92,809	179,852	272,661		-21,780	147,476	125,696
2046		217,308	192,225	409,533		-18,184	135,102	116,918
2047		188,927	205,451	394,378		-18,839	121,877	103,038
2048		153,199		153,199		-19,871		-19,871
2049		45,087		45,087		-23,118		-23,118
2050		63,644		63,644		-22,571		-22,571
2051		121,244		121,244		-20,996		-20,996
2052		145,781		145,781		-20,135		-20,135
2053		160,129		160,129		-19,771		-19,771
2054		4,734		4,734		-24,306		-24,306
2055		122,138		122,138		-32,089		-32,089
TOTALS		10,799,117	7,642,690	18,441,807		4,277,951	8,578,237	12,856,188

LEGEND

CCO = CAPITALIZED CONTRACT OBLIGATIONS
CONS = CONSERVATION
GEN = GENERATION
TRANS = TRANSMISSION

1/ INCLUDES PAYMENTS FOR THE IRRIGATION ASSISTANCE

FY 2005

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)

A	B	C	D	E
FISCAL YEAR ENDING SEPT 30	GENERATION UNAMORTIZED INVESTMENT	GENERATION TERM SCHEDULE	TRANSMISSION UNAMORTIZED INVESTMENT	TRANSMISSION TERM SCHEDULE
CUMULATIVE 1999	3,931,367	4,929,735		
2000	4,091,434	5,069,908		
2001	4,680,530	5,606,476		
2002	4,820,591	5,802,213		
2003	4,972,153	5,753,375		
2004	5,238,493	5,927,695		
2005	5,309,729	5,999,944		
2006	5,191,076	5,946,744		
2007	5,084,444	5,845,138		
2008	4,980,102	5,511,963		
2009	4,859,848	5,393,848		
2010	4,731,529	5,331,031		
2011	4,828,554	5,493,962		
2012	4,760,168	5,396,721		
2013	4,640,806	5,390,307		
2014	4,378,434	5,376,025		
2015	4,204,597	5,392,027		
2016	3,991,893	5,412,002		
2017	3,663,359	5,432,501		
2018	3,280,291	5,592,865		
2019	2,872,115	5,441,471		
2020	2,400,217	5,288,680		
2021	1,973,335	5,268,132		
2022	1,596,367	5,355,834		
2023	1,055,861	5,258,253		
2024	403,961	5,253,365		
2025		5,084,898		
2026		4,855,453		
2027		4,865,551		
2028		4,819,064		
2029		4,649,147		
2030		4,653,875		
2031		4,613,531		
2032		4,443,798		
2033		4,167,968		
2034		4,185,007		
2035		4,182,932		
2036		4,183,081		
2037		4,184,091		
2038		4,167,404		
2039		4,215,056		
2040		4,212,770		
2041		4,234,275		
2042		4,245,041		
2043		4,117,911		
2044		4,026,842		
2045		3,850,898		
2046		3,700,998		
2047		3,669,618		
2048		3,596,439		
2049		3,521,850		
2050		3,447,615		
2051		2,947,424		
2052		2,819,003		
2053		2,778,758		
2054		2,544,865		

FY 2006

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
GENERATION

A	B	C	D	E	F	G	H	I	J
	INVESTMENT PLACED IN SERVICE						IRRIGATION ASSISTANCE		
FISCAL YEAR ENDING SEPT 30	INITIAL 1/ PROJECT THRU 9-30 +	REPLACE-MENTS THRU 9-30 =	CUMULATIVE AMOUNT IN SERVICE -	AMORTI-ZATION 9-30 -	DISCRETIONARY AMORTIZATION =	UNAMORTIZED INVESTMENT	CUMULATIVE AMOUNT IN SERVICE -	AMORTI-ZATION =	UNAMORTIZED AMOUNT
CUMULATIVE 1999	5,443,896	179,484	5,623,380	1,692,013		3,931,367	770,437		770,437
2000	210,182		5,833,562	50,115		4,091,434	770,437		770,437
2001	612,002		6,445,564	19,474	3,432	4,680,530	770,437	16,560	753,877
2002	261,737		6,707,301	66,000	55,676	4,820,591	770,437		753,877
2003	207,568		6,914,869	46,062	9,945	4,972,152	770,437		753,877
2004	333,432		7,248,301	67,091	2	5,238,491	770,437	739	753,138
2005	219,995		7,468,296	103,173	26,421	5,328,892	770,437		753,138
2006	254,899		7,723,195	53,200	75,308	5,455,283	770,437		753,138
2007			7,723,195	61,732	45,002	5,348,549	770,437	2,919	750,219
2008			7,723,195	104,300	7	5,244,242	770,437	31	750,188
2009			7,723,195	118,115	2,130	5,123,997	770,437	7,709	742,479
2010			7,723,195	62,726	65,582	4,995,689	777,379	6,566	742,855
2011		281,643	8,004,838	43,569	75,272	5,158,491	777,379		742,855
2012		40,108	8,044,946	55,618	39,932	5,103,049	780,855	811	745,520
2013		189,123	8,234,069	152,907	107,273	5,031,992	800,648	87,326	677,987
2014		76,787	8,310,856	70,758	243,298	4,794,723	800,648	48,554	629,433
2015		210,572	8,521,428	147,107	179,696	4,678,492	805,755	54,101	580,439
2016		136,945	8,658,373	99,919	205,854	4,509,664	811,149	99,517	486,316
2017		157,119	8,815,492	90,095	344,029	4,232,659	811,149	62,246	424,070
2018		375,737	9,191,229	99,197	554,138	3,955,061	862,336	25,460	449,797
2019		19,913	9,211,142	42,023	348,968	3,583,983	873,238	88,259	372,440
2020		29,185	9,240,327	66,576	400,483	3,146,109	873,238	36,743	335,697
2021		160,526	9,400,853	112,696	390,556	2,803,383	912,445	16,826	358,078
2022		231,073	9,631,926	30,411	482,747	2,521,298	951,494	44,911	352,216
2023		99,098	9,731,024	1,725	569,409	2,049,262	951,494	9,663	342,553
2024		3,188	9,734,212	115	605,114	1,447,221	993,300	21,072	363,287
2025		219,706	9,953,918	128,014	477,331	1,061,582	1,013,337	51,516	331,808
2026		89,609	10,043,527	80,899	584,420	485,872	1,013,337	18,876	312,932
2027		206,451	10,249,978	48,066	644,257		1,045,565	22,271	322,889
2028		222,776	10,472,754		222,776		1,078,951	255,473	100,802
2029		182,529	10,655,283		182,529		1,078,951		100,802
2030		37,938	10,693,221		37,938		1,108,914		130,765
2031		150,359	10,843,580		150,359		1,138,877	44,797	115,931
2032		140,461	10,984,041		140,461		1,138,877		115,931
2033		62,747	11,046,788		62,747		1,179,301		156,355
2034		42,345	11,089,133		42,345		1,219,725	29,207	167,572
2035		189,603	11,278,736		189,603		1,219,725		167,572
2036		76,768	11,355,504		76,768		1,248,274		196,121
2037		120,905	11,476,409		120,905		1,276,982	29,310	195,519
2038		13,508	11,489,917		13,508		1,276,982		195,519
2039		157,084	11,647,001		157,084		1,306,293		224,830
2040		639	11,647,640		639		1,340,128	33,836	224,829
2041		118,296	11,765,936		118,296		1,340,128		224,829
2042		58,552	11,824,488		58,552		1,374,822		259,523
2043		54,742	11,879,230		54,742		1,409,517	32,941	261,277
2044		68,740	11,947,970		68,740		1,409,517		261,277
2045		119,819	12,067,789		119,819		1,442,458		294,218
2046		280,543	12,348,332		280,543		1,475,557	39,725	287,592
2047		243,904	12,592,236		243,904		1,475,557		287,592
2048		197,781	12,790,017		197,781		1,515,440		327,475
2049		58,206	12,848,223		58,206		1,555,323	23,256	344,102
2050		82,164	12,930,387		82,164		1,555,323		344,102
2051		156,524	13,086,911		156,524		1,578,738		367,517
2052		188,205	13,275,116		188,205		1,603,084	31,316	360,547
2053		206,728	13,481,844		206,728		1,603,084		360,547
2054		6,111	13,487,955		6,111		1,634,400		391,863
2055		157,679	13,645,634		157,679		1,665,716	24,194	398,985
2056		101,320	13,746,954		101,320		1,665,716		398,985
TOTALS	7,543,711	6,203,243		3,713,696	10,033,258			1,266,731	

1/ GROSS INITIAL PROJECT INVESTMENT, RETIREMENTS INCLUDED

2C

FY 2006

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY

(ALL AMOUNTS IN $1000)

PRINCIPAL PAYMENTS

A	B	C	D	E	F	G	H	I	J
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION		
YEAR	APPROPRIATIONS		BONDS		APPROPRIATIONS		APPROPRIATIONS		IRRIGATION
ENDING	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 1/	TRANS	GEN	AMORTIZATION
SEPT 30									
2006				1		128,500		7	
2007				45,002		61,503		229	2,919
2008				104,307					31
2009				79,830		40,415			7,709
2010				88,482		39,745		81	
2011				49,439		69,237		165	
2012						95,443		107	811
2013				152,800		107,273		107	49,796
2014				61,080		252,002		974	48,554
2015				147,000		179,696		107	54,101
2016				27,000		234,541		44,232	64,264
2017				74,732		208,926		150,466	62,246
2018				38,317		513,118		101,900	25,460
2019				41,825		200,707		148,459	67,001
2020				109,155		276,970		80,934	36,743
2021				425,738		77,514			16,826
2022				20,637		487,801		4,720	15,831
2023						563,978		7,156	9,663
2024						496,740		108,489	21,072
2025						382,110		223,235	18,288
2026						527,880		137,439	18,876
2027						601,007		91,316	22,271
2028						22,987		199,789	210,676
2029						182,529			
2030						37,938			
2031						149,269		1,090	
2032						136,560		3,901	
2033						54,913		7,834	
2034						42,345			
2035						189,603			
2036						76,069		699	
2037						55,800		65,105	
2038						3,229		10,279	
2039						157,084			
2040						639			
2041						118,296			
2042						56,337		2,215	
2043						46,083		8,659	
2044						68,740			
2045						119,819			
2046						279,509		1,034	
2047						22,802		221,102	
2048						135,672		62,109	
2049						58,206			
2050						82,164			
2051						156,524			
2052						111,211		76,994	
2053						84,593		122,135	
2054						6,111			
2055						157,679			
2056						96,369		4,951	
TOTALS				1,465,345		8,254,186		1,888,019	753,138

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

2D

FY 2006

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY

(ALL AMOUNTS IN $1000)

PRINCIPAL PAYMENTS

A	B	C	D	E
	PRINCIPAL COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS			
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2006	303,909	8,279	12,903	
2007	334,062	8,466	13,661	
2008	362,107	9,234	14,460	
2009	373,083	9,831	15,328	
2010	390,977		15,801	
2011	447,733		16,741	
2012	518,637		17,772	
2013	256,168		18,888	
2014	274,401		16,087	
2015	307,002		13,628	
2016	315,952		12,358	
2017	282,241		13,006	
2018	131,337		13,681	
2019	32,919		14,390	
2020	35,174		15,149	
2021	37,584		15,943	
2022	40,158		13,856	
2023	42,909		14,970	
2024	45,849		15,789	
2025	48,989		1,529	
2026	52,345		1,000	
2027	55,931		1,000	
2028	59,762		1,000	
2029	63,855		1,000	
2030	68,230			
2031	72,903			
2032	77,897			
2033	83,233			
2034	88,935			
2035	95,027			
2036	101,536			
2037	108,491			
2038	115,923			
2039	123,863			
2040	132,348			
2041	141,414			
2042	151,101			
2043	161,451			
2044	172,511			
2045	184,328			
2046	196,954			
2047	210,445			
TOTALS	7,099,674	35,810	289,940	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2006

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
INTEREST PAYMENTS

A	B	C	D	E	F	G	H	I
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION	
YEAR	APPROPRIATIONS		BONDS 1/		APPROPRIATIONS		APPROPRIATIONS	
ENDING	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 2/	TRANS	GEN
SEPT 30								
2006				81,307		236,722		38,605
2007				85,591		232,360		38,657
2008				82,832		228,067		38,640
2009				76,738		228,067		38,640
2010				74,454		225,214		38,640
2011				65,676		230,456		38,635
2012				61,792		234,632		38,624
2013				53,507		232,603		40,511
2014				43,845		230,729		42,398
2015				39,608		220,797		42,328
2016				28,128		217,794		42,329
2017				23,623		209,100		40,775
2018				12,807		201,862		38,221
2019				17,979		171,152		37,540
2020				16,958		158,230		26,926
2021				23,774		143,862		21,141
2022				-21,831		149,351		22,767
2023				-24,172		125,263		26,245
2024				-24,632		91,967		27,962
2025				-24,662		68,782		21,509
2026				-24,681		55,285		8,247
2027				-24,681		30,359		2,774
2028				-24,681		678		5,913
2029				-24,681		5,310		
2030				-24,715		1,091		
2031				-24,715		4,189		32
2032				-24,715		3,875		115
2033				-24,715		1,616		233
2034				-24,715		1,228		
2035				-24,715		5,461		
2036				-24,715		2,091		21
2037				-24,715		1,613		1,935
2038				-24,715		91		299
2039				-24,715		4,497		
2040				-24,715		19		
2041				-24,715		3,345		
2042				-24,715		1,596		65
2043				-24,715		1,356		257
2044				-24,715		1,967		
2045				-24,715		3,403		
2046				-24,715		7,969		31
2047				-24,715		641		6,552
2048				-24,715		4,022		1,847
2049				-24,715		1,699		
2050				-24,715		2,401		
2051				-24,715		4,404		
2052				-24,715		3,248		2,279
2053				-24,715		2,375		3,602
2054				-24,715		176		
2055				-36,138		4,529		
2056				-36,138		2,697		147
TOTALS				-95,560		4,000,241		735,442

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ NET OF INTEREST INCOME AND AFUDC
2/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

2F

FY 2006

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M

REPAYMENT STUDY

(ALL AMOUNTS IN $1000)

INTEREST PAYMENTS

INTEREST COMPONENT OF CAPITALIZED CONTRACT OBLIGATIONS

A	B	C	D	E
FISCAL YEAR ENDING SEPT 30	SUPPLY SYSTEM PROJECTS GEN	TROJAN GEN	HANFORD GEN	IDAHO FALLS & CONSERVATION GEN
2006	235,896	1,730	12,333	
2007	223,395	1,247	11,578	
2008	207,503	725	10,766	
2009	189,486	-10,330	9,877	
2010	169,758		8,954	
2011	132,598		7,992	
2012	81,686		9,171	
2013	105,470		4,020	
2014	81,241		7,362	
2015	47,942		6,465	
2016	31,056		5,766	
2017	-11,570		5,127	
2018	-22,482		4,451	
2019	301,708		3,735	
2020	299,453		2,981	
2021	297,043		-752	
2022	294,469		1,834	
2023	291,718		943	
2024	288,778		-13,341	
2025	285,638		27	
2026	282,282			
2027	278,696			
2028	274,865			
2029	270,772			
2030	266,397			
2031	261,724			
2032	256,730			
2033	251,394			
2034	245,692			
2035	239,600			
2036	233,091			
2037	226,136			
2038	218,704			
2039	210,764			
2040	202,279			
2041	193,213			
2042	183,526			
2043	173,176			
2044	162,116			
2045	150,299			
2046	137,673			
2047	124,182			
TOTALS	8,374,097	-6,628	99,289	

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION

FY 2006

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)
SUMMARY TOTALS

A	B	C	D	E	F	G	H	I
FISCAL YEAR ENDING SEPT 30	PRINCIPAL 1/ TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT	INTEREST TRANSMISSION PAYMENT	CONS & GEN PAYMENT	COMPONENT OF CCO	TOTAL PAYMENT
2006		128,508	325,091	453,599		356,634	249,959	606,593
2007		109,653	356,189	465,842		356,608	236,220	592,828
2008		104,338	385,801	490,139		349,539	218,994	568,533
2009		127,954	398,242	526,196		343,445	189,033	532,478
2010		128,308	406,778	535,086		338,308	178,712	517,020
2011		118,841	464,474	583,315		334,767	140,590	475,357
2012		96,361	536,409	632,770		335,048	90,857	425,905
2013		309,976	275,056	585,032		326,621	109,490	436,111
2014		362,610	290,488	653,098		316,972	88,603	405,575
2015		380,904	320,630	701,534		302,733	54,407	357,140
2016		370,037	328,310	698,347		288,251	36,822	325,073
2017		496,370	295,247	791,617		273,498	-6,443	267,055
2018		678,795	145,018	823,813		252,890	-18,031	234,859
2019		457,992	47,309	505,301		226,671	305,443	532,114
2020		503,802	50,323	554,125		202,114	302,434	504,548
2021		520,078	53,527	573,605		188,777	296,291	485,068
2022		528,989	54,014	583,003		150,287	296,303	446,590
2023		580,797	57,879	638,676		127,336	292,661	419,997
2024		626,301	61,638	687,939		95,297	275,437	370,734
2025		623,633	50,518	674,151		65,629	285,665	351,294
2026		684,195	53,345	737,540		38,851	282,282	321,133
2027		714,594	56,931	771,525		8,452	278,696	287,148
2028		433,452	60,762	494,214		-18,090	274,865	256,775
2029		182,529	64,855	247,384		-19,371	270,772	251,401
2030		37,938	68,230	106,168		-23,624	266,397	242,773
2031		150,359	72,903	223,262		-20,494	261,724	241,230
2032		140,461	77,897	218,358		-20,725	256,730	236,005
2033		62,747	83,233	145,980		-22,866	251,394	228,528
2034		42,345	88,935	131,280		-23,487	245,692	222,205
2035		189,603	95,027	284,630		-19,254	239,600	220,346
2036		76,768	101,536	178,304		-22,603	233,091	210,488
2037		120,905	108,491	229,396		-21,167	226,136	204,969
2038		13,508	115,923	129,431		-24,325	218,704	194,379
2039		157,084	123,863	280,947		-20,218	210,764	190,546
2040		639	132,348	132,987		-24,696	202,279	177,583
2041		118,296	141,414	259,710		-21,370	193,213	171,843
2042		58,552	151,101	209,653		-23,054	183,526	160,472
2043		54,742	161,451	216,193		-23,102	173,176	150,074
2044		68,740	172,511	241,251		-22,748	162,116	139,368
2045		119,819	184,328	304,147		-21,312	150,299	128,987
2046		280,543	196,954	477,497		-16,715	137,673	120,958
2047		243,904	210,445	454,349		-17,522	124,182	106,660
2048		197,781		197,781		-18,846		-18,846
2049		58,206		58,206		-23,016		-23,016
2050		82,164		82,164		-22,314		-22,314
2051		156,524		156,524		-20,311		-20,311
2052		188,205		188,205		-19,188		-19,188
2053		206,728		206,728		-18,738		-18,738
2054		6,111		6,111		-24,539		-24,539
2055		157,679		157,679		-31,609		-31,609
2056		101,320		101,320		-33,294		-33,294
TOTALS		12,360,688	7,425,424	19,786,112		4,640,123	8,466,758	13,106,881

LEGEND

CCO = CAPITALIZED CONTRACT OBLIGATIONS
CONS = CONSERVATION
GEN = GENERATION
TRANS = TRANSMISSION

1/ INCLUDES PAYMENTS FOR THE IRRIGATION ASSISTANCE

FY 2006

F E D E R A L   C O L U M B I A   R I V E R   P O W E R   S Y S T E M
REPAYMENT STUDY
(ALL AMOUNTS IN $1000)

A FISCAL YEAR ENDING SEPT 30	B GENERATION UNAMORTIZED INVESTMENT	C TERM SCHEDULE	D TRANSMISSION UNAMORTIZED INVESTMENT	E TERM SCHEDULE
CUMULATIVE 1999	3,931,367	4,929,735		
2000	4,091,434	5,069,908		
2001	4,680,530	5,606,476		
2002	4,820,591	5,802,213		
2003	4,972,152	5,753,375		
2004	5,238,491	5,927,695		
2005	5,328,892	5,999,944		
2006	5,455,283	6,201,643		
2007	5,348,549	6,100,037		
2008	5,244,242	5,766,862		
2009	5,123,997	5,648,747		
2010	4,995,689	5,585,930		
2011	5,158,491	5,812,345		
2012	5,103,049	5,724,145		
2013	5,031,992	5,760,361		
2014	4,794,723	5,763,387		
2015	4,678,492	5,826,852		
2016	4,509,664	5,861,174		
2017	4,232,659	5,913,625		
2018	3,955,061	6,144,960		
2019	3,583,983	5,998,010		
2020	3,146,109	5,851,790		
2021	2,803,383	5,815,772		
2022	2,521,298	5,948,705		
2023	2,049,262	5,873,071		
2024	1,447,221	5,868,876		
2025	1,061,582	5,721,078		
2026	485,872	5,493,597		
2027		5,539,113		
2028		5,542,161		
2029		5,398,298		
2030		5,405,455		
2031		5,365,187		
2032		5,206,168		
2033		4,941,345		
2034		4,963,342		
2035		4,974,694		
2036		4,974,963		
2037		4,997,376		
2038		4,981,318		
2039		5,042,837		
2040		5,040,688		
2041		5,070,997		
2042		5,085,151		
2043		4,966,852		
2044		4,877,413		
2045		4,705,623		
2046		4,555,919		
2047		4,562,572		
2048		4,493,721		
2049		4,421,809		
2050		4,359,314		
2051		3,795,623		
2052		3,668,953		
2053		3,640,448		
2054		3,406,555		
2055		3,307,323		

TABLE 16

Application of Amortization
Generation

FY 2006 Repayment Study

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2000	COLUMBIA BASIN	1995	2000	25	25	.06620		25
	HUNGRY HORSE	1995	2000	6	6	.06620	R	6
	HUNGRY HORSE	1995	2000	84	84	.06620		84
	BUREAU DIRECT FUND	1997	2000	50,000	50,000	.06500		50,000
	BPA PROGRAM	1995	2025	67	67	.07700		67
	LOWER MONUMENTAL	1996	2016	668	668	.07290		668
	JOHN DAY	1996	2016	1,072	1,072	.07290		1,072
	BONNEVILLE	1996	2016	834	834	.07290	R	834
	ALBENI FALLS	1996	2016	130	130	.07290		130
	LOWER GRANITE	1995	2017	458	458	.07290		458
	LOWER GRANITE	1995	2017	388	388	.07290		388
	LOWER GRANITE	1995	2017	77	77	.07290	R	77
	GREEN PETER-FOSTER	1967	2017	11,919	11,919	.07290		11,919
	COLUMBIA BASIN	1967	2017	758	758	.07290		758
	GREEN PETER-FOSTER	1987	2018	1	1	.07280		1
	GREEN PETER-FOSTER	1986	2018	3	3	.07280		3
	GREEN PETER-FOSTER	1985	2018	16	16	.07280		16
	GREEN PETER-FOSTER	1983	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1982	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1981	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1980	2018	40	40	.07280	R	40
	GREEN PETER-FOSTER	1979	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1978	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1977	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1976	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1975	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1974	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1973	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1972	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1971	2018	39	39	.07280	R	39
	GREEN PETER-FOSTER	1970	2018	40	40	.07280	R	40
	GREEN PETER-FOSTER	1969	2018	39	39	.07280	R	39
	JOHN DAY	1968	2018	21,686	21,686	.07280		21,686
	GREEN PETER-FOSTER	1968	2018	12,180	12,180	.07280		1,652
	TOTAL							90,431

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2001	COLUMBIA BASIN	1956	2001	259	259	.06710	R	259
	COLUMBIA BASIN	1956	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1957	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1957	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1958	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1958	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1959	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1959	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1960	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1960	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1961	2001	259	259	.06710	R	259
	COLUMBIA BASIN	1961	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1962	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1962	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1963	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1963	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1964	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1964	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1965	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1965	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1966	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1966	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1967	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1967	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1968	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1968	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1969	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1969	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1970	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1970	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1971	2001	259	259	.06710	R	259
	COLUMBIA BASIN	1971	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1972	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1972	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1973	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1973	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1974	2001	258	258	.06710	R	258
	COLUMBIA BASIN	1974	2001	48	48	.06710	R	48
	COLUMBIA BASIN	1975	2001	258	258	.06710	R	258

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
COLUMBIA BASIN	1975	2001	48	48	.06710	R	48
COLUMBIA BASIN	1976	2001	259	259	.06710	R	259
COLUMBIA BASIN	1976	2001	48	48	.06710	R	48
COLUMBIA BASIN	1977	2001	258	258	.06710	R	258
COLUMBIA BASIN	1977	2001	48	48	.06710	R	48
COLUMBIA BASIN	1978	2001	258	258	.06710	R	258
COLUMBIA BASIN	1978	2001	48	48	.06710	R	48
COLUMBIA BASIN	1979	2001	258	258	.06710	R	258
COLUMBIA BASIN	1979	2001	48	48	.06710	R	48
COLUMBIA BASIN	1980	2001	258	258	.06710	R	258
COLUMBIA BASIN	1980	2001	48	48	.06710	R	48
COLUMBIA BASIN	1981	2001	259	259	.06710	R	259
COLUMBIA BASIN	1981	2001	48	48	.06710	R	48
COLUMBIA BASIN	1982	2001	258	258	.06710	R	258
COLUMBIA BASIN	1982	2001	48	48	.06710	R	48
COLUMBIA BASIN	1983	2001	258	258	.06710	R	258
COLUMBIA BASIN	1983	2001	48	48	.06710	R	48
COLUMBIA BASIN	1985	2001	236	236	.06710		236
COLUMBIA BASIN	1985	2001	11	11	.06710		11
COLUMBIA BASIN	1955	2001	258	258	.06710	R	258
COLUMBIA BASIN	1954	2001	48	48	.06710	R	48
COLUMBIA BASIN	1954	2001	258	258	.06710	R	258
BOISE	1986	2001	89	89	.06710		89
COLUMBIA BASIN	1986	2001	127	127	.06710		127
COLUMBIA BASIN	1955	2001	48	48	.06710	R	48
COLUMBIA BASIN	1987	2001	13	13	.06710		13
COLUMBIA BASIN	1951	2001	7,719	7,719	.06710		7,719
COLUMBIA BASIN	1951	2001	1,437	1,437	.06710		1,437
COLUMBIA BASIN	1993	2001	45	45	.06710		45
COLUMBIA BASIN	1952	2001	258	258	.06710	R	258
COLUMBIA BASIN	1952	2001	48	48	.06710	R	48
COLUMBIA BASIN	1953	2001	258	258	.06710	R	258
COLUMBIA BASIN	1953	2001	48	48	.06710	R	48
GREEN PETER-FOSTER	1968	2018	12,180	10,528	.07280		10,528
ICE HARBOR	1995	2019	849	849	.07270		849
ICE HARBOR	1995	2019	171	171	.07270		171
ICE HARBOR	1995	2019	84	84	.07270		84
LOWER MONUMENTAL	1969	2019	25,083	25,083	.07270		22,681
TOTAL							53,787

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2002	BPA CONSERVATION	1989	2002	66,000	66,000	.08650		66,000
	LOWER MONUMENTAL	1969	2019	25,083	2,402	.07270		2,402
	JOHN DAY	1969	2019	96,104	96,104	.07270		38,999
	TOTAL							107,401
2003	FISH, WILDLIFE & ENVIRONMENTAL	1999	2003	20,000	20,000	.06300		20,000
	BPA PROGRAM	1996	2003	5,622	5,622	.05900		5,622
	HUNGRY HORSE	1955	2003	17	17	.06840	R	17
	HUNGRY HORSE	1956	2003	17	17	.06840	R	17
	HUNGRY HORSE	1956	2003	1	1	.06840	R	1
	HUNGRY HORSE	1957	2003	18	18	.06840	R	18
	HUNGRY HORSE	1957	2003	1	1	.06840	R	1
	HUNGRY HORSE	1958	2003	18	18	.06840	R	18
	HUNGRY HORSE	1958	2003	1	1	.06840	R	1
	HUNGRY HORSE	1959	2003	18	18	.06840	R	18
	HUNGRY HORSE	1959	2003	1	1	.06840	R	1
	HUNGRY HORSE	1960	2003	18	18	.06840	R	18
	HUNGRY HORSE	1960	2003	1	1	.06840	R	1
	HUNGRY HORSE	1961	2003	18	18	.06840	R	18
	HUNGRY HORSE	1961	2003	1	1	.06840	R	1
	HUNGRY HORSE	1962	2003	18	18	.06840	R	18
	HUNGRY HORSE	1962	2003	1	1	.06840	R	1
	HUNGRY HORSE	1963	2003	18	18	.06840	R	18
	HUNGRY HORSE	1963	2003	1	1	.06840	R	1
	HUNGRY HORSE	1964	2003	17	17	.06840	R	17
	HUNGRY HORSE	1964	2003	1	1	.06840	R	1
	HUNGRY HORSE	1965	2003	17	17	.06840	R	17
	HUNGRY HORSE	1965	2003	1	1	.06840	R	1
	HUNGRY HORSE	1966	2003	17	17	.06840	R	17
	HUNGRY HORSE	1966	2003	1	1	.06840	R	1
	HUNGRY HORSE	1967	2003	18	18	.06840	R	18
	HUNGRY HORSE	1967	2003	1	1	.06840	R	1
	HUNGRY HORSE	1968	2003	18	18	.06840	R	18
	HUNGRY HORSE	1968	2003	1	1	.06840	R	1
	HUNGRY HORSE	1953	2003	490	490	.06840		490
	HUNGRY HORSE	1953	2003	16,359	16,359	.06840		16,359
	DETROIT-BIG CLIFF	1953	2003	3,078	3,078	.06840		3,078
	HUNGRY HORSE	1969	2003	18	18	.06840	R	18

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
HUNGRY HORSE	1969	2003	1	1	.06840	R	1
HUNGRY HORSE	1955	2003	1	1	.06840	R	1
HUNGRY HORSE	1970	2003	18	18	.06840	R	18
HUNGRY HORSE	1970	2003	1	1	.06840	R	1
HUNGRY HORSE	1971	2003	18	18	.06840	R	18
HUNGRY HORSE	1971	2003	1	1	.06840	R	1
HUNGRY HORSE	1972	2003	18	18	.06840	R	18
HUNGRY HORSE	1972	2003	1	1	.06840	R	1
HUNGRY HORSE	1973	2003	18	18	.06840	R	18
HUNGRY HORSE	1973	2003	1	1	.06840	R	1
HUNGRY HORSE	1974	2003	17	17	.06840	R	17
HUNGRY HORSE	1974	2003	1	1	.06840	R	1
HUNGRY HORSE	1975	2003	17	17	.06840	R	17
HUNGRY HORSE	1975	2003	1	1	.06840	R	1
HUNGRY HORSE	1976	2003	10	10	.06840	R	10
HUNGRY HORSE	1976	2003	1	1	.06840	R	1
HUNGRY HORSE	1954	2003	17	17	.06840	R	17
HUNGRY HORSE	1977	2003	18	18	.06840	R	18
HUNGRY HORSE	1977	2003	1	1	.06840	R	1
HUNGRY HORSE	1954	2003	1	1	.06840	R	1
HUNGRY HORSE	1978	2003	18	18	.06840	R	18
HUNGRY HORSE	1978	2003	1	1	.06840	R	1
HUNGRY HORSE	1979	2003	18	18	.06840	R	18
HUNGRY HORSE	1979	2003	1	1	.06840	R	1
HUNGRY HORSE	1980	2003	18	18	.06840	R	18
HUNGRY HORSE	1980	2003	1	1	.06840	R	1
HUNGRY HORSE	1981	2003	1	1	.06840	R	1
HUNGRY HORSE	1981	2003	1	1	.06840	R	1
HUNGRY HORSE	1982	2003	1	1	.06840	R	1
HUNGRY HORSE	1983	2003	12	12	.06840	R	12
HUNGRY HORSE	1983	2003	1	1	.06840	R	1
JOHN DAY	1969	2019	96,104	57,105	.07270		26,922
TOTAL							72,984

APPLICATION OF AMORTIZATION GENERATION FY 2006 REPAYMENT STUDY FOR 2002 FINAL RATE PROPOSAL

INVESTMENT PAID

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2004	DETROIT-BIG CLIFF	1956	2004	19	19	.06880	R	19
	BUREAU DIRECT FUND	1999	2004	20,000	20,000	.06400		20,000
	DETROIT-BIG CLIFF	1957	2004	18	18	.06880	R	18
	BPA PROGRAM	1997	2004	7,400	7,400	.06800		7,400
	DETROIT-BIG CLIFF	1958	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1959	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1960	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1961	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1962	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1963	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1964	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1965	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1966	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1967	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1968	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1969	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1970	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1971	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1972	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1973	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1974	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1975	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1976	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1954	2004	20,162	20,162	.06880		20,162
	DETROIT-BIG CLIFF	1977	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1978	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1979	2004	18	18	.06880	R	18
	MCNARY	1954	2004	35,757	35,757	.06880		35,757
	DETROIT-BIG CLIFF	1980	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1981	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1982	2004	19	19	.06880	R	19
	DETROIT-BIG CLIFF	1983	2004	18	18	.06880	R	18
	DETROIT-BIG CLIFF	1985	2004	6	6	.06880		6
	DETROIT-BIG CLIFF	1987	2004	3	3	.06880		3
	DETROIT-BIG CLIFF	1955	2004	18	18	.06880	R	18
	JOHN DAY	1969	2019	96,104	30,183	.07270		8,421
	TOTAL							92,285

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2005	MCNARY	1955	2005	53,493	53,493	.06910		53,493
	ALBENI FALLS	1956	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1956	2005	52	52	.06910	R	52
	ALBENI FALLS	1957	2005	10	10	.06910	R	10
	LOOKOUT POINT-DEXTER	1957	2005	51	51	.06910	R	51
	ALBENI FALLS	1958	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1958	2005	51	51	.06910	R	51
	ALBENI FALLS	1959	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1955	2005	28,417	28,417	.06910		28,417
	LOOKOUT POINT-DEXTER	1959	2005	51	51	.06910	R	51
	ALBENI FALLS	1960	2005	10	10	.06910	R	10
	LOOKOUT POINT-DEXTER	1960	2005	51	51	.06910	R	51
	ALBENI FALLS	1961	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1961	2005	52	52	.06910	R	52
	ALBENI FALLS	1962	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1962	2005	51	51	.06910	R	51
	ALBENI FALLS	1963	2005	10	10	.06910	R	10
	LOOKOUT POINT-DEXTER	1963	2005	51	51	.06910	R	51
	ALBENI FALLS	1964	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1964	2005	51	51	.06910	R	51
	ALBENI FALLS	1965	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1965	2005	51	51	.06910	R	51
	ALBENI FALLS	1966	2005	10	10	.06910	R	10
	LOOKOUT POINT-DEXTER	1966	2005	51	51	.06910	R	51
	ALBENI FALLS	1967	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1967	2005	52	52	.06910	R	52
	ALBENI FALLS	1968	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1968	2005	51	51	.06910	R	51
	ALBENI FALLS	1969	2005	10	10	.06910	R	10
	LOOKOUT POINT-DEXTER	1969	2005	51	51	.06910	R	51
	ALBENI FALLS	1970	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1970	2005	51	51	.06910	R	51
	ALBENI FALLS	1971	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1971	2005	51	51	.06910	R	51
	ALBENI FALLS	1972	2005	10	10	.06910	R	10
	LOOKOUT POINT-DEXTER	1972	2005	51	51	.06910	R	51
	ALBENI FALLS	1973	2005	11	11	.06910	R	11
	LOOKOUT POINT-DEXTER	1973	2005	52	52	.06910	R	52
	ALBENI FALLS	1974	2005	11	11	.06910	R	11

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
LOOKOUT POINT-DEXTER	1974	2005	51	51	.06910	R	51
ALBENI FALLS	1975	2005	10	10	.06910	R	10
LOOKOUT POINT-DEXTER	1975	2005	51	51	.06910	R	51
ALBENI FALLS	1976	2005	11	11	.06910	R	11
LOOKOUT POINT-DEXTER	1976	2005	51	51	.06910	R	51
ALBENI FALLS	1977	2005	11	11	.06910	R	11
LOOKOUT POINT-DEXTER	1977	2005	51	51	.06910	R	51
ALBENI FALLS	1978	2005	10	10	.06910	R	10
LOOKOUT POINT-DEXTER	1978	2005	51	51	.06910	R	51
ALBENI FALLS	1979	2005	11	11	.06910	R	11
LOOKOUT POINT-DEXTER	1979	2005	52	52	.06910	R	52
ALBENI FALLS	1980	2005	11	11	.06910	R	11
ALBENI FALLS	1955	2005	16,854	16,854	.06910		16,854
LOOKOUT POINT-DEXTER	1980	2005	51	51	.06910	R	51
ALBENI FALLS	1981	2005	10	10	.06910	R	10
LOOKOUT POINT-DEXTER	1981	2005	51	51	.06910	R	51
ALBENI FALLS	1982	2005	11	11	.06910	R	11
LOOKOUT POINT-DEXTER	1982	2005	51	51	.06910	R	51
ALBENI FALLS	1983	2005	11	11	.06910	R	11
CHIEF JOSEPH	1955	2005	2,262	2,262	.06910		2,262
LOOKOUT POINT-DEXTER	1983	2005	51	51	.06910	R	51
ALBENI FALLS	1985	2005	7	7	.06910		7
LOOKOUT POINT-DEXTER	1985	2005	52	52	.06910		52
ALBENI FALLS	1986	2005	293	293	.06910		293
LOOKOUT POINT-DEXTER	1986	2005	42	42	.06910		42
ALBENI FALLS	1987	2005	12	12	.06910		12
LOOKOUT POINT-DEXTER	1987	2005	9	9	.06910		9
BPA PROGRAM	2000	2045	4,100	4,100	.07540		4,100
BUREAU DIRECT FUND	2000	2045	95,369	95,369	.07540		26,657
YAKIMA-ROZA	1987	2008	2	2	.07020		2
MINIDOKA	1987	2008	16	16	.07020		16
YAKIMA-ROZA	1986	2008	6	6	.07020		6
MINIDOKA	1986	2008	21	21	.07020		21
YAKIMA-ROZA	1985	2008	69	69	.07020		69
MINIDOKA	1985	2008	21	21	.07020		21
CHIEF JOSEPH	1985	2008	46	46	.07020		46
MINIDOKA	1983	2008	20	20	.07020	R	20
MINIDOKA	1983	2008	65	65	.07020	R	65
CHIEF JOSEPH	1983	2008	224	224	.07020	R	224

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
MINIDOKA	1982	2008	19	19	.07020	R	19
MINIDOKA	1982	2008	75	75	.07020	R	75
CHIEF JOSEPH	1982	2008	223	223	.07020	R	223
MINIDOKA	1981	2008	20	20	.07020	R	20
MINIDOKA	1981	2008	75	75	.07020	R	75
CHIEF JOSEPH	1981	2008	223	223	.07020	R	223
MINIDOKA	1980	2008	20	20	.07020	R	20
MINIDOKA	1980	2008	75	75	.07020	R	75
CHIEF JOSEPH	1980	2008	223	223	.07020	R	223
MINIDOKA	1979	2008	19	19	.07020	R	19
MINIDOKA	1979	2008	75	75	.07020	R	75
CHIEF JOSEPH	1979	2008	223	223	.07020	R	223
MINIDOKA	1978	2008	20	20	.07020	R	20
MINIDOKA	1978	2008	75	75	.07020	R	75
CHIEF JOSEPH	1978	2008	224	224	.07020	R	224
MINIDOKA	1977	2008	56	56	.07020	R	56
CHIEF JOSEPH	1977	2008	223	223	.07020	R	223
CHIEF JOSEPH	1976	2008	223	223	.07020	R	223
CHIEF JOSEPH	1975	2008	223	223	.07020	R	223
CHIEF JOSEPH	1974	2008	223	223	.07020	R	223
CHIEF JOSEPH	1973	2008	224	224	.07020	R	224
CHIEF JOSEPH	1972	2008	223	223	.07020	R	223
CHIEF JOSEPH	1971	2008	223	223	.07020	R	223
CHIEF JOSEPH	1970	2008	223	223	.07020	R	223
THE DALLES	1996	2008	196	196	.07020		196
CHIEF JOSEPH	1969	2008	223	223	.07020	R	223
CHIEF JOSEPH	1968	2008	224	224	.07020	R	224
CHIEF JOSEPH	1967	2008	223	223	.07020	R	223
CHIEF JOSEPH	1966	2008	223	223	.07020	R	223
CHIEF JOSEPH	1965	2008	223	223	.07020	R	223
CHIEF JOSEPH	1964	2008	223	223	.07020	R	223
CHIEF JOSEPH	1963	2008	224	224	.07020	R	224
CHIEF JOSEPH	1962	2008	223	223	.07020	R	223
CHIEF JOSEPH	1961	2008	223	223	.07020	R	223
CHIEF JOSEPH	1960	2008	223	223	.07020	R	223
CHIEF JOSEPH	1959	2008	223	223	.07020	R	223
YAKIMA-ROZA	1958	2008	161	161	.07020		161
YAKIMA-ROZA	1958	2008	533	533	.07020		533
THE DALLES	1958	2008	33,988	33,988	.07020		6,902

APPLICATION OF AMORTIZATION GENERATION FY 2006 REPAYMENT STUDY FOR 2002 FINAL RATE PROPOSAL

INVESTMENT PAID

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	TOTAL							148,097
2006	CHIEF JOSEPH	1956	2006	13,643	13,643	.06950		13,643
	MCNARY	1956	2006	38,748	38,748	.06950		38,748
	BOISE	1996	2006	7	7	.06950		7
	MCNARY	1996	2006	778	778	.06950		778
	DETROIT-BIG CLIFF	1996	2006	24	24	.06950		24
	THE DALLES	1958	2008	33,988	27,086	.07020		27,086
	CHIEF JOSEPH	1958	2008	31,901	31,901	.07020		31,901
	MCNARY	1987	2007	24	24	.06980		24
	MCNARY	1986	2007	454	454	.06980		454
	MCNARY	1985	2007	557	557	.06980		557
	MCNARY	1983	2007	468	468	.06980	R	468
	MCNARY	1982	2007	467	467	.06980	R	467
	MCNARY	1981	2007	468	468	.06980	R	468
	MCNARY	1980	2007	468	468	.06980	R	468
	MCNARY	1979	2007	468	468	.06980	R	468
	MCNARY	1978	2007	468	468	.06980	R	468
	MCNARY	1977	2007	467	467	.06980	R	467
	MCNARY	1976	2007	468	468	.06980	R	468
	MCNARY	1975	2007	468	468	.06980	R	468
	MCNARY	1974	2007	468	468	.06980	R	468
	MCNARY	1973	2007	467	467	.06980	R	467
	MCNARY	1972	2007	468	468	.06980	R	468
	MCNARY	1971	2007	468	468	.06980	R	468
	MCNARY	1970	2007	468	468	.06980	R	468
	MCNARY	1969	2007	468	468	.06980	R	468
	MCNARY	1968	2007	468	468	.06980	R	468
	MCNARY	1967	2007	467	467	.06980	R	467
	MCNARY	1966	2007	468	468	.06980	R	468
	MCNARY	1965	2007	468	468	.06980	R	468
	MCNARY	1964	2007	468	468	.06980	R	468
	MCNARY	1963	2007	468	468	.06980	R	468
	MCNARY	1962	2007	467	467	.06980	R	467
	MCNARY	1961	2007	468	468	.06980	R	468
	MCNARY	1960	2007	468	468	.06980	R	468
	MCNARY	1959	2007	468	468	.06980	R	468
	MCNARY	1958	2007	468	468	.06980	R	468
	MCNARY	1957	2007	24,985	24,985	.06980		3,091

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	TOTAL							128,476
2007	CHIEF JOSEPH	1957	2007	39,586	39,586	.06980		39,586
	MCNARY	1957	2007	24,985	21,894	.06980		21,894
	BOISE	1997	2007	9	9	.06950		9
	HUNGRY HORSE	1997	2007	154	154	.06950		154
	MINIDOKA	1997	2007	66	66	.06950		66
	FISH, WILDLIFE & ENVIRONMENTAL	1993	2008	20,000	20,000	.06950		20,000
	BUREAU DIRECT FUND	1998	2008	25,000	25,000	.06000		25,000
	TOTAL							106,709
2008	BPA CONSERVATION	1998	2008	104,300	104,300	.05300		104,300
	BUREAU DIRECT FUND	2000	2045	95,369	68,712	.07540		1
	TOTAL							104,301
2009	BPA CONSERVATION	1998	2009	37,700	37,700	.06000		37,700
	BPA CONSERVATION	1989	2009	40,000	40,000	.08550		40,000
	THE DALLES	1959	2009	40,415	40,415	.07060		40,415
	BUREAU DIRECT FUND	2000	2045	95,369	68,711	.07540		2,113
	TOTAL							120,228
2010	MINIDOKA	2000	2010	81	81	.06520		81
	THE DALLES	1960	2010	39,179	39,179	.07090		39,179
	MCNARY	1995	2010	509	509	.07090		509
	ALBENI FALLS	1995	2010	17	17	.07090		17
	FISH, WILDLIFE & ENVIRONMENTAL	1995	2010	22,900	22,900	.07200		22,900
	BONNEVILLE	1995	2010	25	25	.07090	R	25
	CHIEF JOSEPH	1995	2010	15	15	.07090		15
	BUREAU DIRECT FUND	2000	2045	95,369	66,598	.07540		65,566
	TOTAL							128,292
2011	BPA CONSERVATION	1996	2011	30,000	30,000	.06700		30,000
	MINIDOKA	2001	2011	80	80	.06190		80
	THE DALLES	1986	2011	95	95	.07130		95
	BOISE	2001	2011	4	4	.06190		4
	THE DALLES	1961	2011	9,492	9,492	.07130		9,492
	BOISE	2001	2011	27	27	.06190		27
	THE DALLES	1962	2011	56	56	.07130	R	56
	THE DALLES	1963	2011	57	57	.07130	R	57

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
THE DALLES	1964	2011	57	57	.07130	R	57
THE DALLES	1965	2011	56	56	.07130	R	56
THE DALLES	1966	2011	57	57	.07130	R	57
THE DALLES	1967	2011	57	57	.07130	R	57
DWORSHAK	1996	2011	107	107	.07130		107
THE DALLES	1968	2011	56	56	.07130	R	56
THE DALLES	1996	2011	457	457	.07130		457
MINIDOKA	1996	2011	54	54	.07130		54
THE DALLES	1969	2011	57	57	.07130	R	57
THE DALLES	1970	2011	57	57	.07130	R	57
THE DALLES	1971	2011	56	56	.07130	R	56
MCNARY	1996	2011	3	3	.07130		3
THE DALLES	1985	2011	95	95	.07130		95
THE DALLES	1972	2011	57	57	.07130	R	57
THE DALLES	1973	2011	57	57	.07130	R	57
THE DALLES	1974	2011	56	56	.07130	R	56
THE DALLES	1975	2011	57	57	.07130	R	57
LOWER GRANITE	1996	2011	255	255	.07130		255
THE DALLES	1976	2011	57	57	.07130	R	57
THE DALLES	1977	2011	56	56	.07130	R	56
THE DALLES	1978	2011	57	57	.07130	R	57
THE DALLES	1979	2011	57	57	.07130	R	57
THE DALLES	1980	2011	56	56	.07130	R	56
JOHN DAY	1996	2011	237	237	.07130		237
THE DALLES	1981	2011	57	57	.07130	R	57
THE DALLES	1987	2011	1,417	1,417	.07130		1,417
THE DALLES	1982	2011	57	57	.07130	R	57
THE DALLES	1983	2011	56	56	.07130	R	56
BUREAU DIRECT FUND	2000	2045	95,369	1,032	.07540		1,032
JOHN DAY	1969	2019	96,104	21,762	.07270		21,762
LOWER MONUMENTAL	1983	2020	214	214	.07250	R	214
GREEN PETER-FOSTER	1995	2020	11	11	.07250		11
GREEN PETER-FOSTER	1995	2020	24	24	.07250		24
BONNEVILLE	1995	2020	22	22	.07250	R	22
BONNEVILLE	1995	2020	20	20	.07250		20
LOWER MONUMENTAL	1982	2020	214	214	.07250	R	214
LOWER MONUMENTAL	1981	2020	214	214	.07250	R	214
LOWER MONUMENTAL	1980	2020	214	214	.07250	R	214
LOWER MONUMENTAL	1979	2020	214	214	.07250	R	214

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LOWER MONUMENTAL	1987	2020	3	3	.07250		3
	LOWER MONUMENTAL	1978	2020	214	214	.07250	R	214
	JOHN DAY	1995	2020	79	79	.07250		79
	LOWER MONUMENTAL	1977	2020	214	214	.07250	R	214
	LOWER MONUMENTAL	1976	2020	214	214	.07250	R	214
	LOWER MONUMENTAL	1975	2020	214	214	.07250	R	214
	LOWER MONUMENTAL	1985	2020	8	8	.07250		8
	LOWER MONUMENTAL	1974	2020	214	214	.07250	R	214
	LOWER MONUMENTAL	1973	2020	214	214	.07250	R	214
	LOWER MONUMENTAL	1972	2020	214	214	.07250	R	214
	LOWER MONUMENTAL	1971	2020	214	214	.07250	R	214
	LOWER MONUMENTAL	1970	2020	51,218	51,218	.07250		50,557
	TOTAL							119,869
2012	ICE HARBOR	1986	2012	137	137	.07160		137
	MINIDOKA	2002	2012	80	80	.05940		80
	HILLS CREEK	1962	2012	9,264	9,264	.07160		9,264
	ICE HARBOR	1962	2012	44,308	44,308	.07160		44,308
	ICE HARBOR	1962	2012	493	493	.07160		493
	HILLS CREEK	1963	2012	12	12	.07160	R	12
	BOISE	2002	2012	27	27	.05940		27
	ICE HARBOR	1963	2012	46	46	.07160	R	46
	ICE HARBOR	1963	2012	1	1	.07160	R	1
	HILLS CREEK	1964	2012	13	13	.07160	R	13
	ICE HARBOR	1964	2012	46	46	.07160	R	46
	ICE HARBOR	1964	2012	1	1	.07160	R	1
	HILLS CREEK	1965	2012	13	13	.07160	R	13
	ICE HARBOR	1965	2012	46	46	.07160	R	46
	ICE HARBOR	1965	2012	1	1	.07160	R	1
	HILLS CREEK	1966	2012	13	13	.07160	R	13
	ICE HARBOR	1983	2012	1	1	.07160	R	1
	ICE HARBOR	1983	2012	46	46	.07160	R	46
	ICE HARBOR	1966	2012	46	46	.07160	R	46
	ICE HARBOR	1966	2012	1	1	.07160	R	1
	HILLS CREEK	1983	2012	13	13	.07160	R	13
	HILLS CREEK	1967	2012	13	13	.07160	R	13
	ICE HARBOR	1967	2012	46	46	.07160	R	46
	ICE HARBOR	1967	2012	1	1	.07160	R	1
	HILLS CREEK	1968	2012	13	13	.07160	R	13

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
ICE HARBOR	1968	2012	46	46	.07160	R	46
ICE HARBOR	1968	2012	1	1	.07160	R	1
HILLS CREEK	1969	2012	13	13	.07160	R	13
ICE HARBOR	1969	2012	46	46	.07160	R	46
ICE HARBOR	1969	2012	1	1	.07160	R	1
HILLS CREEK	1970	2012	13	13	.07160	R	13
ICE HARBOR	1970	2012	46	46	.07160	R	46
ICE HARBOR	1970	2012	1	1	.07160	R	1
HILLS CREEK	1971	2012	13	13	.07160	R	13
HILLS CREEK	1985	2012	6	6	.07160		6
ICE HARBOR	1971	2012	46	46	.07160	R	46
ICE HARBOR	1971	2012	1	1	.07160	R	1
ICE HARBOR	1987	2012	3	3	.07160		3
HILLS CREEK	1972	2012	13	13	.07160	R	13
ICE HARBOR	1972	2012	46	46	.07160	R	46
ICE HARBOR	1972	2012	1	1	.07160	R	1
HILLS CREEK	1973	2012	13	13	.07160	R	13
ICE HARBOR	1973	2012	46	46	.07160	R	46
ICE HARBOR	1973	2012	1	1	.07160	R	1
ICE HARBOR	1982	2012	1	1	.07160	R	1
ICE HARBOR	1982	2012	46	46	.07160	R	46
HILLS CREEK	1974	2012	13	13	.07160	R	13
HILLS CREEK	1982	2012	13	13	.07160	R	13
ICE HARBOR	1974	2012	46	46	.07160	R	46
ICE HARBOR	1974	2012	1	1	.07160	R	1
HILLS CREEK	1975	2012	13	13	.07160	R	13
ICE HARBOR	1975	2012	46	46	.07160	R	46
ICE HARBOR	1975	2012	1	1	.07160	R	1
HILLS CREEK	1976	2012	13	13	.07160	R	13
ICE HARBOR	1976	2012	46	46	.07160	R	46
ICE HARBOR	1976	2012	1	1	.07160	R	1
HILLS CREEK	1977	2012	13	13	.07160	R	13
ICE HARBOR	1977	2012	46	46	.07160	R	46
ICE HARBOR	1977	2012	1	1	.07160	R	1
ICE HARBOR	1985	2012	41	41	.07160		41
HILLS CREEK	1978	2012	13	13	.07160	R	13
ICE HARBOR	1978	2012	46	46	.07160	R	46
ICE HARBOR	1978	2012	1	1	.07160	R	1
HILLS CREEK	1979	2012	13	13	.07160	R	13

YEAR ------------------------------INVESTMENT PAID------------------------------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	ICE HARBOR	1979	2012	46	46	.07160	R	46
	ICE HARBOR	1979	2012	1	1	.07160	R	1
	HILLS CREEK	1980	2012	13	13	.07160	R	13
	ICE HARBOR	1980	2012	46	46	.07160	R	46
	ICE HARBOR	1980	2012	1	1	.07160	R	1
	ICE HARBOR	1981	2012	1	1	.07160	R	1
	ICE HARBOR	1981	2012	46	46	.07160	R	46
	HILLS CREEK	1981	2012	13	13	.07160	R	13
	LOWER MONUMENTAL	1970	2020	51,218	661	.07250		661
	LITTLE GOOSE	1970	2020	21,301	21,301	.07250		21,301
	JOHN DAY	1970	2020	23,656	23,656	.07250		17,948
	TOTAL							95,528
2013	BPA CONSERVATION	1998	2013	52,800	52,800	.05600		52,800
	FISH, WILDLIFE & ENVIRONMENTAL	1998	2013	60,000	60,000	.06100		60,000
	MINIDOKA	2003	2013	80	80	.05750		80
	BOISE	2003	2013	27	27	.05750		27
	BPA CONSERVATION	1993	2013	40,000	40,000	.06750		40,000
	JOHN DAY	1970	2020	23,656	5,708	.07250		5,708
	LOWER MONUMENTAL	1986	2020	132	132	.07250		132
	COUGAR	1981	2014	20	20	.07230	R	20
	COUGAR	1980	2014	20	20	.07230	R	20
	COUGAR	1979	2014	20	20	.07230	R	20
	COUGAR	1978	2014	20	20	.07230	R	20
	COUGAR	1977	2014	20	20	.07230	R	20
	COUGAR	1986	2014	104	104	.07230		104
	COUGAR	1976	2014	20	20	.07230	R	20
	COUGAR	1982	2014	20	20	.07230	R	20
	COUGAR	1975	2014	20	20	.07230	R	20
	COUGAR	1974	2014	19	19	.07230	R	19
	COUGAR	1973	2014	20	20	.07230	R	20
	COUGAR	1985	2014	1	1	.07230		1
	COUGAR	1972	2014	20	20	.07230	R	20
	COUGAR	1971	2014	20	20	.07230	R	20
	COUGAR	1970	2014	20	20	.07230	R	20
	COUGAR	1969	2014	20	20	.07230	R	20
	COUGAR	1983	2014	20	20	.07230	R	20
	COUGAR	1968	2014	20	20	.07230	R	20
	COUGAR	1987	2014	45	45	.07230		45

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
COUGAR	1967	2014	20	20	.07230	R	20
COUGAR	1966	2014	20	20	.07230	R	20
COUGAR	1965	2014	20	20	.07230	R	20
COUGAR	1964	2014	9,042	9,042	.07230		9,042
LITTLE GOOSE	1980	2021	28	28	.07230	R	28
LITTLE GOOSE	1981	2021	29	29	.07230	R	29
LITTLE GOOSE	1979	2021	29	29	.07230	R	29
LITTLE GOOSE	1985	2021	174	174	.07230		174
LITTLE GOOSE	1978	2021	28	28	.07230	R	28
LITTLE GOOSE	1977	2021	29	29	.07230	R	29
LITTLE GOOSE	1976	2021	28	28	.07230	R	28
LITTLE GOOSE	1975	2021	29	29	.07230	R	29
LITTLE GOOSE	1987	2021	6	6	.07230		6
LITTLE GOOSE	1974	2021	28	28	.07230	R	28
LOWER MONUMENTAL	1996	2021	37	37	.07230		37
LOWER MONUMENTAL	1996	2021	51	51	.07230		51
LITTLE GOOSE	1973	2021	29	29	.07230	R	29
LITTLE GOOSE	1982	2021	28	28	.07230	R	28
LITTLE GOOSE	1972	2021	28	28	.07230	R	28
LITTLE GOOSE	1971	2021	42,962	42,962	.07230		42,962
JOHN DAY	1971	2021	34,974	34,974	.07230		34,974
DWORSHAK	1996	2021	26	26	.07230		26
DWORSHAK	1996	2021	184	184	.07230		184
LITTLE GOOSE	1983	2021	29	29	.07230	R	29
LITTLE GOOSE	1986	2021	239	239	.07230		239
LIBBY	1997	2022	432	432	.07230		432
BONNEVILLE	1997	2022	122	122	.07230		122
JOHN DAY	1997	2022	133	133	.07230		133
ICE HARBOR	1997	2022	66	66	.07230		66
JOHN DAY	1992	2022	19	19	.07210		19
JOHN DAY	1987	2022	706	706	.07210		706
JOHN DAY	1972	2022	11,502	11,502	.07210		11,357
TOTAL							260,148

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2014	BPA PROGRAM	1999	2014	11,080	11,080	.05900		11,080
	MINIDOKA	2004	2014	80	80	.05730		80
	BOISE	2004	2014	27	27	.05730		27
	BPA CONSERVATION	1994	2014	50,000	50,000	.06750		50,000
	JOHN DAY	1972	2022	11,502	145	.07210		145
	JOHN DAY	1990	2022	37	37	.07210		37
	JOHN DAY	1986	2022	3,227	3,227	.07210		3,227
	JOHN DAY	1985	2022	6,490	6,490	.07210		6,490
	JOHN DAY	1989	2022	30	30	.07210		30
	YAKIMA-CHANDLER	1961	2022	1	1	.07210	R	1
	YAKIMA-CHANDLER	1960	2022	1	1	.07210	R	1
	YAKIMA-CHANDLER	1959	2022	1	1	.07210	R	1
	YAKIMA-CHANDLER	1986	2022	455	455	.07210		455
	YAKIMA-CHANDLER	1956	2022	216	216	.07210		216
	YAKIMA-CHANDLER	1956	2022	193	193	.07210		193
	DWORSHAK	1979	2023	3	3	.07190	R	3
	DWORSHAK	1979	2023	518	518	.07190	R	518
	DWORSHAK	1978	2023	3	3	.07190	R	3
	DWORSHAK	1978	2023	518	518	.07190	R	518
	DWORSHAK	1977	2023	3	3	.07190	R	3
	DWORSHAK	1977	2023	518	518	.07190	R	518
	DWORSHAK	1976	2023	3	3	.07190	R	3
	DWORSHAK	1976	2023	518	518	.07190	R	518
	DWORSHAK	1975	2023	3	3	.07190	R	3
	DWORSHAK	1975	2023	518	518	.07190	R	518
	DWORSHAK	1982	2023	518	518	.07190	R	518
	DWORSHAK	1982	2023	3	3	.07190	R	3
	DWORSHAK	1974	2023	3	3	.07190	R	3
	DWORSHAK	1974	2023	515	515	.07190	R	515
	THE DALLES	1973	2023	21,983	21,983	.07190		21,983
	DWORSHAK	1973	2023	803	803	.07190		803
	DWORSHAK	1973	2023	132,996	132,996	.07190		132,996
	DWORSHAK	1980	2023	3	3	.07190	R	3
	DWORSHAK	1981	2023	3	3	.07190	R	3
	DWORSHAK	1980	2023	518	518	.07190	R	518
	DWORSHAK	1981	2023	518	518	.07190	R	518
	DWORSHAK	1987	2023	5	5	.07190		5
	DWORSHAK	1983	2023	523	523	.07190	R	523
	DWORSHAK	1983	2023	3	3	.07190	R	3

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	DWORSHAK	1986	2023	197	197	.07190		197
	DWORSHAK	1985	2023	1,141	1,141	.07190		1,141
	THE DALLES	1974	2024	7,268	7,268	.07170		7,268
	LOWER GRANITE	1987	2025	8	8	.07160		8
	LOWER GRANITE	1977	2025	510	510	.07160	R	510
	LOWER GRANITE	1980	2025	510	510	.07160	R	510
	LOWER GRANITE	1976	2025	510	510	.07160	R	510
	LOWER GRANITE	1985	2025	328	328	.07160		328
	LOWER GRANITE	1981	2025	510	510	.07160	R	510
	LOWER GRANITE	1975	2025	117,645	117,645	.07160		70,016
	TOTAL							313,980
2015	FISH, WILDLIFE & ENVIRONMENTAL	2000	2015	27,000	27,000	.07240		27,000
	BPA CONSERVATION	1995	2015	85,000	85,000	.07500		85,000
	MINIDOKA	2005	2015	80	80	.05670		80
	BOISE	2005	2015	27	27	.05670		27
	BUREAU DIRECT FUND	1995	2015	35,000	35,000	.07500		35,000
	LOWER GRANITE	1975	2025	117,645	47,629	.07160		47,629
	LIBBY	1975	2025	48,138	48,138	.07160		48,138
	COLUMBIA BASIN - 3RD PWR HOUSE	1975	2025	7,435	7,435	.07160		7,435
	COLUMBIA BASIN - 3RD PWR HOUSE	1975	2025	36,690	36,690	.07160		36,690
	LOWER GRANITE	1982	2025	510	510	.07160	R	510
	LOWER GRANITE	1983	2025	510	510	.07160	R	510
	LOWER GRANITE	1995	2025	96	96	.07160		96
	LOWER GRANITE	1986	2025	215	215	.07160		215
	LOWER GRANITE	1979	2025	510	510	.07160	R	510
	LOWER GRANITE	1978	2025	510	510	.07160	R	510
	LIBBY	1979	2026	1,465	1,465	.07150	R	1,465
	LIBBY	1977	2026	1,465	1,465	.07150	R	1,465
	LIBBY	1976	2026	153,432	153,432	.07150		34,378
	TOTAL							326,658

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2016	FISH, WILDLIFE & ENVIRONMENTAL	2001	2016	27,000	27,000	.06920		27,000
	BONNEVILLE	2011	2016	72,812	72,812	.05488	R	72,812
	BOISE	2006	2016	27	27	.05610		27
	MINIDOKA	2006	2016	80	80	.05610		80
	LIBBY	1976	2026	153,432	119,054	.07150		119,054
	ICE HARBOR	1976	2026	228	228	.07150		228
	ICE HARBOR	1976	2026	20,472	20,472	.07150		20,472
	LIBBY	1978	2026	1,465	1,465	.07150	R	1,465
	COLUMBIA BASIN - 3RD PWR HOUSE	1976	2026	8,037	8,037	.07150		8,037
	COLUMBIA BASIN - 3RD PWR HOUSE	1976	2026	41,330	41,330	.07150		41,330
	LIBBY	1985	2026	518	518	.07150		518
	LIBBY	1980	2026	1,465	1,465	.07150	R	1,465
	COLUMBIA BASIN	1996	2026	76	76	.07150		76
	LIBBY	1981	2026	1,465	1,465	.07150	R	1,465
	LIBBY	1987	2026	2	2	.07150		2
	LIBBY	1982	2026	1,465	1,465	.07150	R	1,465
	ICE HARBOR	1985	2026	21	21	.07150		21
	MCNARY	1996	2026	74	74	.07150		74
	MCNARY	1996	2026	277	277	.07150		277
	LIBBY	1989	2026	1	1	.07150		1
	LIBBY	1983	2026	1,465	1,465	.07150	R	1,465
	LIBBY	1986	2026	283	283	.07150		283
	LOST CREEK	1978	2027	58	58	.07150	R	58
	LOST CREEK	1977	2027	13,413	13,413	.07150		7,928
	TOTAL							305,603
2017	FISH, WILDLIFE & ENVIRONMENTAL	2002	2017	34,732	34,732	.06690		34,732
	BPA CONSERVATION	1996	2017	40,000	40,000	.07200		40,000
	ICE HARBOR	2012	2017	15,363	15,363	.05488	R	15,363
	LOST CREEK	1977	2027	13,413	5,485	.07150		5,485
	LOST CREEK	1981	2027	60	60	.07150	R	60
	COLUMBIA BASIN - 3RD PWR HOUSE	1977	2027	7,964	7,964	.07150		7,964
	COLUMBIA BASIN - 3RD PWR HOUSE	1977	2027	42,764	42,764	.07150		42,764
	CHIEF JOSEPH	1977	2027	30,512	30,512	.07150		30,512
	BONNEVILLE	1977	2027	15,670	15,670	.07150		15,670
	LOST CREEK	1985	2027	12	12	.07150		12
	LOST CREEK	1987	2027	4	4	.07150		4
	LOST CREEK	1980	2027	60	60	.07150	R	60
	LOST CREEK	1982	2027	60	60	.07150	R	60

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LOST CREEK	1983	2027	60	60	.07150	R	60
	LOST CREEK	1986	2027	6	6	.07150		6
	LOST CREEK	1979	2027	60	60	.07150	R	60
	COLUMBIA BASIN - 3RD PWR HOUSE	1978	2028	7,896	7,896	.07150		7,896
	COLUMBIA BASIN - 3RD PWR HOUSE	1978	2028	42,399	42,399	.07150		42,399
	CHIEF JOSEPH	1978	2028	75,669	75,669	.07150		75,669
	LITTLE GOOSE	1978	2028	49,578	49,578	.07150		49,578
	LOWER GRANITE	1978	2028	40,611	40,611	.07150		40,611
	LITTLE GOOSE	1985	2028	47	47	.07150		47
	CHIEF JOSEPH	1985	2029	16,372	16,372	.07150		16,372
	LOWER MONUMENTAL	1985	2029	256	256	.07150		256
	LOWER GRANITE	1994	2029	1,551	1,551	.07150		1,551
	COLUMBIA BASIN - 3RD PWR HOUSE	1979	2029	15,666	15,666	.07150		6,741
	TOTAL							433,932
2018	FISH, WILDLIFE & ENVIRONMENTAL	2003	2018	38,317	38,317	.06500		38,317
	LOWER SNAKE F AND W	2013	2018	54	54	.05488	R	54
	MCNARY	2011	2018	32	32	.05554	R	32
	LOWER SNAKE F AND W	2011	2018	642	642	.05554	R	642
	LOWER MONUMENTAL	2011	2018	26	26	.05554	R	26
	LOOKOUT POINT-DEXTER	2011	2018	17	17	.05554	R	17
	LIBBY	2011	2018	77	77	.05554	R	77
	ICE HARBOR	2011	2018	29,048	29,048	.05554	R	29,048
	BONNEVILLE	2011	2018	30,984	30,984	.05554	R	30,984
	COLUMBIA BASIN - 3RD PWR HOUSE	1979	2029	15,666	8,925	.07150		8,925
	COLUMBIA BASIN - 3RD PWR HOUSE	1979	2029	84,118	84,118	.07150		84,118
	LIBBY	1994	2029	152	152	.07150		152
	CHIEF JOSEPH	1979	2029	60,079	60,079	.07150		60,079
	CHIEF JOSEPH	1990	2029	4,505	4,505	.07150		4,505
	CHIEF JOSEPH	1986	2029	5,363	5,363	.07150		5,363
	CHIEF JOSEPH	1989	2029	2,227	2,227	.07150		2,227
	CHIEF JOSEPH	1987	2029	3,036	3,036	.07150		3,036
	LOWER MONUMENTAL	1979	2029	40,669	40,669	.07150		40,669
	CHIEF JOSEPH	1988	2029	2,722	2,722	.07150		2,722
	DWORSHAK	1995	2030	218	218	.07150		218
	HUNGRY HORSE	1995	2030	1,195	1,195	.07150	R	1,195
	LIBBY	1995	2030	15	15	.07150	R	15
	LIBBY	1995	2030	41	41	.07150		41
	LIBBY	1995	2030	94	94	.07150	R	94

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	COLUMBIA BASIN	1995	2030	25	25	.07150		25
	HUNGRY HORSE	1995	2030	536	536	.07150	R	536
	COLUMBIA BASIN	1996	2031	109	109	.07150		109
	LOST CREEK	1996	2031	31	31	.07150		31
	COLUMBIA BASIN	1996	2031	251	251	.07150		251
	LOWER GRANITE	1996	2031	206	206	.07150		206
	ICE HARBOR	1996	2031	78	78	.07150		78
	DWORSHAK	1996	2031	6	6	.07150		6
	CHIEF JOSEPH	1996	2031	27	27	.07150	R	27
	DWORSHAK	1996	2031	203	203	.07150		203
	BONNEVILLE - 2ND POWER HOUSE	1981	2031	455	455	.07150		455
	BONNEVILLE - 2ND POWER HOUSE	1981	2031	40,964	40,964	.07150		40,964
	BONNEVILLE	1996	2031	22	22	.07150		22
	BONNEVILLE - 2ND POWER HOUSE	1982	2032	203,535	203,535	.07150		203,535
	BONNEVILLE - 2ND POWER HOUSE	1982	2032	2,264	2,264	.07150		2,264
	MCNARY	1997	2032	30	30	.07150		30
	BONNEVILLE	1997	2032	518	518	.07150		518
	CHIEF JOSEPH	1997	2032	166	166	.07150		166
	LOWER SNAKE F AND W	1983	2033	9,967	9,967	.07150		9,967
	BONNEVILLE - 2ND POWER HOUSE	1986	2033	30,578	30,578	.07150		30,578
	COLUMBIA BASIN - 3RD PWR HOUSE	1985	2033	41,772	41,772	.07150		41,772
	COLUMBIA BASIN - 3RD PWR HOUSE	1985	2033	107	107	.07150		107
	COLUMBIA BASIN - 3RD PWR HOUSE	1985	2033	2,060	2,060	.07150		2,060
	COLUMBIA BASIN - 3RD PWR HOUSE	1990	2033	6,383	6,383	.07150		6,383
	BONNEVILLE - 2ND POWER HOUSE	1983	2033	62,409	62,409	.07150		280
	TOTAL							653,129
2019	THE DALLES	2014	2019	49	49	.05488	R	49
	FISH, WILDLIFE & ENVIRONMENTAL	2004	2019	35,825	35,825	.06480		35,825
	BPA CONSERVATION	1999	2019	6,000	6,000	.07470		6,000
	MCNARY	2011	2019	67	67	.05571	R	67
	JOHN DAY	2012	2019	31	31	.05554	R	31
	LOOKOUT POINT-DEXTER	2011	2019	6	6	.05571	R	6
	LITTLE GOOSE	2011	2019	45	45	.05571	R	45
	BONNEVILLE - 2ND POWER HOUSE	1983	2033	62,409	62,129	.07150		62,129
	BONNEVILLE - 2ND POWER HOUSE	1983	2033	694	694	.07150		694
	COLUMBIA BASIN - 3RD PWR HOUSE	1983	2033	712	712	.07150		712
	BONNEVILLE - 2ND POWER HOUSE	1990	2033	1,588	1,588	.07150		1,588
	COLUMBIA BASIN - 3RD PWR HOUSE	1983	2033	13,003	13,003	.07150		13,003

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	COLUMBIA BASIN - 3RD PWR HOUSE	1984	2033	16,965	16,965	.07150		16,965
	COLUMBIA BASIN - 3RD PWR HOUSE	1987	2033	1,730	1,730	.07150		1,730
	COLUMBIA BASIN - 3RD PWR HOUSE	1989	2033	10,902	10,902	.07150		10,902
	COLUMBIA BASIN - 3RD PWR HOUSE	1987	2033	14,439	14,439	.07150		14,439
	BONNEVILLE - 2ND POWER HOUSE	1989	2033	1,232	1,232	.07150		1,232
	BONNEVILLE - 2ND POWER HOUSE	1987	2033	2,801	2,801	.07150		2,801
	COLUMBIA BASIN - 3RD PWR HOUSE	1986	2033	15,538	15,538	.07150		15,538
	COLUMBIA BASIN - 3RD PWR HOUSE	1984	2033	13,192	13,192	.07150		13,192
	COLUMBIA BASIN - 3RD PWR HOUSE	1988	2033	2,294	2,294	.07150		2,294
	BONNEVILLE - 2ND POWER HOUSE	1985	2033	9,138	9,138	.07150		9,138
	COLUMBIA BASIN - 3RD PWR HOUSE	1984	2033	3,160	3,160	.07150		3,160
	COLUMBIA BASIN - 3RD PWR HOUSE	1988	2033	4,351	4,351	.07150		4,351
	BONNEVILLE - 2ND POWER HOUSE	1988	2033	1,271	1,271	.07150		1,271
	COLUMBIA BASIN - 3RD PWR HOUSE	1986	2033	1,851	1,851	.07150		1,851
	JOHN DAY	1995	2035	22	22	.07150		22
	LOWER SNAKE F AND W	1985	2035	47,921	47,921	.07150		47,921
	JOHN DAY	1995	2035	121	121	.07150		121
	JOHN DAY	1995	2035	52	52	.07150		52
	LOWER MONUMENTAL	1996	2036	264	264	.07150	R	264
	LOWER SNAKE F AND W	1987	2037	72,536	72,536	.07150		72,536
	LOWER SNAKE F AND W	1988	2038	805	805	.07150		805
	LIBBY	1988	2038	14,781	14,781	.07150		14,781
	LITTLE GOOSE	1995	2040	17	17	.07150		17
	LITTLE GOOSE	1995	2040	450	450	.07150		450
	LITTLE GOOSE	1995	2040	733	733	.07150	R	733
	LOWER SNAKE F AND W	1990	2040	1,557	1,557	.07150		1,557
	ICE HARBOR	1996	2041	371	371	.07150	R	371
	LOWER SNAKE F AND W	1991	2041	4,411	4,411	.07150		4,411
	LOWER SNAKE F AND W	1993	2043	71,632	71,632	.07150		27,716
	TOTAL							390,770
2020	FISH, WILDLIFE & ENVIRONMENTAL	2005	2020	33,988	33,988	.06440		33,988
	BPA CONSERVATION	2000	2020	32,555	32,555	.07400		32,555
	COUGAR	2012	2020	4	4	.05571	R	4
	LITTLE GOOSE	2013	2020	26	26	.05554	R	26
	COUGAR	2013	2020	3	3	.05554	R	3
	LOWER SNAKE F AND W	1993	2043	71,632	43,916	.07150		43,916
	COLUMBIA BASIN - 3RD PWR HOUSE	1994	2044	12,631	12,631	.07150		12,631
	CHIEF JOSEPH	1994	2044	4,017	4,017	.07150		4,017

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
BONNEVILLE - 2ND POWER HOUSE	1994	2044	5,700	5,700	.07150		5,700
LOWER SNAKE F AND W	1994	2044	4,619	4,619	.07150		4,619
ALBENI FALLS	1995	2045	531	531	.07150		531
COLUMBIA BASIN	1995	2045	292	292	.07150	R	292
BONNEVILLE	1995	2045	410	410	.07150	R	410
JOHN DAY	1995	2045	608	608	.07150		608
BONNEVILLE	1995	2045	243	243	.07150		243
BONNEVILLE - 2ND POWER HOUSE	1995	2045	3,791	3,791	.07150		3,791
LOOKOUT POINT-DEXTER	1995	2045	33	33	.07150		33
LOOKOUT POINT-DEXTER	1995	2045	39	39	.07150		39
CHIEF JOSEPH	1995	2045	147	147	.07150		147
LOST CREEK	1995	2045	94	94	.07150		94
ALBENI FALLS	1995	2045	1,105	1,105	.07150		1,105
JOHN DAY	1995	2045	37	37	.07150		37
BONNEVILLE	1995	2045	440	440	.07150	R	440
LOWER MONUMENTAL	1995	2045	41	41	.07150		41
DETROIT-BIG CLIFF	1995	2045	38	38	.07150		38
LOWER MONUMENTAL	1995	2045	99	99	.07150		99
LOWER MONUMENTAL	1995	2045	624	624	.07150		624
LOWER MONUMENTAL	1995	2045	1,122	1,122	.07150	R	1,122
LOWER SNAKE F AND W	1995	2045	2,162	2,162	.07150		2,162
DWORSHAK	1995	2045	1,162	1,162	.07150		1,162
ALBENI FALLS	1995	2045	443	443	.07150		443
MCNARY	1995	2045	16	16	.07150		16
HUNGRY HORSE	1995	2045	6,190	6,190	.07150		6,190
COLUMBIA RIVER FISH MITIGATION	1995	2045	703	703	.07150		703
COLUMBIA BASIN	1995	2045	2,453	2,453	.07150		2,453
JOHN DAY	1995	2045	7,653	7,653	.07150	R	7,653
CHIEF JOSEPH	1995	2045	712	712	.07150	R	712
CHIEF JOSEPH	1995	2045	562	562	.07150		562
CHIEF JOSEPH	1995	2045	784	784	.07150		784
LITTLE GOOSE	1996	2046	10	10	.07150		10
DWORSHAK	1996	2046	3	3	.07150		3
LOWER SNAKE F AND W	1996	2046	10,185	10,185	.07150		10,185
DWORSHAK	1996	2046	4	4	.07150		4
LITTLE GOOSE	1996	2046	520	520	.07150	R	520
LITTLE GOOSE	1996	2046	211	211	.07150		211
BONNEVILLE	1996	2046	109	109	.07150		109
MCNARY	1996	2046	619	619	.07150		619

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
LITTLE GOOSE	1996	2046	241	241	.07150		241
BONNEVILLE	1996	2046	223	223	.07150		223
LOST CREEK	1996	2046	24	24	.07150		24
DWORSHAK	1996	2046	46	46	.07150		46
LOWER GRANITE	1996	2046	625	625	.07150		625
BONNEVILLE	1996	2046	142	142	.07150		142
LOWER MONUMENTAL	1996	2046	10	10	.07150		10
CHIEF JOSEPH	1996	2046	3	3	.07150	R	3
THE DALLES	1996	2046	1,991	1,991	.07150		1,991
CHIEF JOSEPH	1996	2046	4	4	.07150	R	4
BONNEVILLE	1996	2046	1,322	1,322	.07150	R	1,322
COLUMBIA BASIN	1996	2046	368	368	.07150		368
CHIEF JOSEPH	1996	2046	729	729	.07150		729
CHIEF JOSEPH	1996	2046	355	355	.07150		355
COLUMBIA RIVER FISH MITIGATION	1996	2046	42,357	42,357	.07150		42,357
HUNGRY HORSE	1996	2046	2	2	.07150		2
HUNGRY HORSE	1996	2046	15	15	.07150		15
BONNEVILLE	1996	2046	751	751	.07150		751
GREEN PETER-FOSTER	1996	2046	26	26	.07150		26
LOWER GRANITE	1996	2046	9	9	.07150	R	9
HILLS CREEK	1996	2046	28	28	.07150		28
BOISE	1996	2046	450	450	.07150		450
LITTLE GOOSE	1996	2046	10	10	.07150	R	10
BOISE	1996	2046	656	656	.07150		656
BONNEVILLE - 2ND POWER HOUSE	1996	2046	376	376	.07150		376
BONNEVILLE	1996	2046	18	18	.07150		18
BONNEVILLE	1996	2046	18	18	.07150		18
BONNEVILLE	1996	2046	80	80	.07150		80
COLUMBIA BASIN	1996	2046	426	426	.07150		426
LITTLE GOOSE	1996	2046	3,909	3,909	.07150	R	3,909
DWORSHAK	1997	2047	7,588	7,588	.07150		7,588
COUGAR	1997	2047	26	26	.07150		26
LIBBY	1997	2047	660	660	.07150		660
ALBENI FALLS	1997	2047	477	477	.07150		477
HUNGRY HORSE	1997	2047	216	216	.07150		216
LITTLE GOOSE	1997	2047	1	1	.07150		1
BOISE	1997	2047	2,284	2,284	.07150		2,284
LOWER GRANITE	1997	2047	677	677	.07150		677
JOHN DAY	1997	2047	179	179	.07150		179

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	BONNEVILLE	1997	2047	161	161	.07150		161
	MINIDOKA	1997	2047	51,558	51,558	.07150		51,558
	ICE HARBOR	1997	2047	67	67	.07150		67
	CHIEF JOSEPH	1997	2047	657	657	.07150		657
	COLUMBIA BASIN	1997	2047	3,393	3,393	.07150		3,393
	LOWER SNAKE F AND W	1997	2047	2,173	2,173	.07150		2,173
	BPA PROGRAM	2001	2046	7,600	7,600	.07290		7,600
	BUREAU DIRECT FUND	2001	2046	76,100	76,100	.07290		76,100
	BUREAU DIRECT FUND	2002	2047	89,855	89,855	.07080		71,375
	TOTAL							462,060
2021	FISH, WILDLIFE & ENVIRONMENTAL	2006	2021	34,182	34,182	.06380		34,182
	BPA CONSERVATION	2001	2021	1,000	1,000	.07110		1,000
	LITTLE GOOSE	2011	2021	13	13	.05607	R	13
	DWORSHAK	2013	2021	43	43	.05571	R	43
	BONNEVILLE	2011	2021	127	127	.05607	R	127
	BONNEVILLE	2016	2021	72,812	72,812	.05488	R	72,812
	BONNEVILLE	2013	2021	4,519	4,519	.05571	R	4,519
	BUREAU DIRECT FUND	2002	2047	89,855	18,480	.07080		18,480
	BPA PROGRAM	2002	2047	2,100	2,100	.07080		2,100
	BPA PROGRAM	2004	2049	1,400	1,400	.06900		1,400
	BUREAU DIRECT FUND	2004	2049	61,700	61,700	.06900		61,700
	BUREAU DIRECT FUND	2003	2048	86,650	86,650	.06890		86,650
	BPA PROGRAM	2003	2048	1,400	1,400	.06890		1,400
	BUREAU DIRECT FUND	2005	2050	62,100	62,100	.06880		62,100
	BPA PROGRAM	2005	2050	1,400	1,400	.06880		1,400
	BUREAU DIRECT FUND	2006	2051	62,100	62,100	.06850		62,100
	BPA PROGRAM	2006	2051	1,400	1,400	.06850		1,400
	BONNEVILLE	2001	2051	17,820	17,820	.06390		17,820
	COLUMBIA BASIN	2001	2051	3,557	3,557	.06390		3,557
	COLUMBIA BASIN	2001	2051	1,163	1,163	.06390		1,163
	THE DALLES	2001	2051	12,528	12,528	.06390		12,528
	COLUMBIA RIVER FISH MITIGATION	2001	2051	457,474	457,474	.06180		59,951
	TOTAL							506,445

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2022	THE DALLES	2015	2022	53	53	.05554	R	53
	DWORSHAK	2015	2022	19	19	.05554	R	19
	ICE HARBOR	2012	2022	14,976	14,976	.05607	R	14,976
	ICE HARBOR	2017	2022	15,363	15,363	.05488	R	15,363
	COLUMBIA RIVER FISH MITIGATION	2001	2051	457,474	397,523	.06180		397,523
	BONNEVILLE	2002	2052	8,910	8,910	.06180		8,910
	COLUMBIA BASIN	2002	2052	1,162	1,162	.06180		1,162
	COLUMBIA RIVER FISH MITIGATION	2002	2052	111,042	111,042	.06180		74,812
	TOTAL							512,818
2023	LOWER SNAKE F AND W	2015	2023	123	123	.05571	R	123
	LOWER SNAKE F AND W	2013	2023	1,168	1,168	.05607	R	1,168
	THE DALLES	2015	2023	80	80	.05571	R	80
	LOWER GRANITE	2011	2023	23	23	.05641	R	23
	GREEN PETER-FOSTER	2015	2023	15	15	.05571	R	15
	GREEN PETER-FOSTER	2016	2023	19	19	.05554	R	19
	LOWER SNAKE F AND W	2018	2023	54	54	.05488	R	54
	DWORSHAK	2013	2023	207	207	.05607	R	207
	LOWER GRANITE	2015	2023	36	36	.05571	R	36
	COLUMBIA RIVER FISH MITIGATION	2002	2052	111,042	36,230	.06180		36,230
	LOWER SNAKE F AND W	2002	2052	794	794	.06180		794
	THE DALLES	2002	2052	12,528	12,528	.06180		12,528
	COLUMBIA RIVER FISH MITIGATION	2000	2050	4,541	4,541	.06125		4,541
	ICE HARBOR	2000	2050	696	696	.06125		696
	COLUMBIA BASIN	2000	2050	1,185	1,185	.06125		1,185
	BONNEVILLE	2000	2050	23,476	23,476	.06125		23,476
	LOWER GRANITE	2000	2050	1,261	1,261	.06125		1,261
	LOWER MONUMENTAL	2000	2050	521	521	.06125		521
	JOHN DAY	2000	2050	17,643	17,643	.06125		17,643
	MCNARY	2000	2050	937	937	.06125		937
	COLUMBIA BASIN	2000	2050	817	817	.06125		817
	COLUMBIA BASIN	2002	2027	507	507	.06120		507
	COLUMBIA BASIN	2004	2054	1,162	1,162	.06000		1,162
	COLUMBIA RIVER FISH MITIGATION	2004	2054	213,203	213,203	.06000		213,203
	MCNARY	2004	2054	7,000	7,000	.06000		7,000
	THE DALLES	2004	2054	12,528	12,528	.06000		12,528
	LOWER SNAKE F AND W	2001	2051	7,649	7,649	.05990		7,649
	BONNEVILLE	2003	2053	22,216	22,216	.05990		22,216
	COLUMBIA BASIN	2003	2053	1,161	1,161	.05990		1,161

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	COLUMBIA RIVER FISH MITIGATION	2003	2053	44,682	44,682	.05990		44,682
	THE DALLES	2003	2053	12,528	12,528	.05990		12,528
	COLUMBIA BASIN	2005	2055	1,162	1,162	.05980		1,162
	COLUMBIA RIVER FISH MITIGATION	2005	2055	91,203	91,203	.05980		91,203
	MCNARY	2005	2055	17,000	17,000	.05980		17,000
	THE DALLES	2005	2055	12,528	12,528	.05980		12,528
	THE DALLES	2006	2056	12,528	12,528	.05950		12,528
	COLUMBIA BASIN	2006	2056	1,162	1,162	.05950		1,162
	MCNARY	2006	2056	17,000	17,000	.05950		9,053
	TOTAL							569,626
2024	DETROIT-BIG CLIFF	2014	2024	36	36	.05607	R	36
	THE DALLES	2019	2024	49	49	.05488	R	49
	LOWER GRANITE	2017	2024	27	27	.05554	R	27
	DETROIT-BIG CLIFF	2017	2024	3	3	.05554	R	3
	MCNARY	2006	2056	17,000	7,947	.05950		7,947
	COLUMBIA RIVER FISH MITIGATION	2006	2056	125,913	125,913	.05950		125,913
	HUNGRY HORSE	2013	2043	534	534	.05949	R	534
	LOWER SNAKE F AND W	2013	2043	2,493	2,493	.05949	R	2,493
	DETROIT-BIG CLIFF	2014	2044	698	698	.05949	R	698
	BONNEVILLE	2011	2046	82,824	82,824	.05949	R	82,824
	ICE HARBOR	2011	2046	7,271	7,271	.05949	R	7,271
	LIBBY	2011	2046	11,804	11,804	.05949	R	11,804
	YAKIMA-CHANDLER	2016	2046	68	68	.05949	R	68
	BONNEVILLE	2012	2047	17	17	.05949	R	17
	BOISE	2017	2047	74	74	.05949	R	74
	MINIDOKA	2017	2047	99	99	.05949	R	99
	LOST CREEK	2012	2047	19	19	.05949	R	19
	LITTLE GOOSE	2013	2048	11,039	11,039	.05949	R	11,039
	CHIEF JOSEPH	2013	2048	78,501	78,501	.05949	R	78,501
	LOWER GRANITE	2013	2048	11,223	11,223	.05949	R	11,223
	COLUMBIA BASIN	2013	2048	61,863	61,863	.05949	R	61,863
	YAKIMA-ROZA	2018	2048	5	5	.05949	R	5
	LOWER MONUMENTAL	2014	2049	10,664	10,664	.05949	R	10,664
	LITTLE GOOSE	2011	2051	11,872	11,872	.05949	R	11,872
	BONNEVILLE	2017	2052	79,089	79,089	.05949	R	79,089
	COLUMBIA BASIN	2017	2052	44,684	44,684	.05949	R	44,684
	HILLS CREEK	2022	2052	389	389	.05949	R	389
	ICE HARBOR	2022	2052	407	407	.05949	R	407

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LOWER SNAKE F AND W	2018	2053	1,282	1,282	.05949	R	1,282
	DWORSHAK	2013	2053	8,674	8,674	.05949	R	8,674
	LOWER GRANITE	2015	2055	7,947	7,947	.05949	R	7,947
	LIBBY	2020	2055	8,798	8,798	.05949	R	8,798
	ICE HARBOR	2016	2056	4,879	4,879	.05949	R	4,879
	LIBBY	2016	2056	17,632	17,632	.05949	R	17,632
	GREEN PETER-FOSTER	2012	2057	2,235	2,235	.05949	R	2,235
	MINIDOKA	2022	2057	3,475	3,475	.05949	R	2,334
	TOTAL							603,393
2025	LOWER SNAKE F AND W	2018	2025	642	642	.05554	R	642
	LOOKOUT POINT-DEXTER	2015	2025	123	123	.05607	R	123
	LOWER MONUMENTAL	2018	2025	26	26	.05554	R	26
	MCNARY	2015	2025	65,841	65,841	.05607	R	65,841
	LOWER GRANITE	2015	2025	1,003	1,003	.05607	R	1,003
	LOOKOUT POINT-DEXTER	2018	2025	17	17	.05554	R	17
	MCNARY	2018	2025	32	32	.05554	R	32
	BONNEVILLE	2013	2025	164	164	.05641	R	164
	ICE HARBOR	2018	2025	29,048	29,048	.05554	R	29,048
	LOWER MONUMENTAL	2017	2025	50	50	.05571	R	50
	ALBENI FALLS	2015	2025	1	1	.05607	R	1
	BONNEVILLE	2018	2025	30,984	30,984	.05554	R	30,984
	LOST CREEK	2013	2025	5	5	.05641	R	5
	LOST CREEK	2017	2025	1	1	.05571	R	1
	LIBBY	2018	2025	77	77	.05554	R	77
	MINIDOKA	2022	2057	3,475	1,141	.05949	R	1,141
	LOST CREEK	2017	2057	1,745	1,745	.05949	R	1,745
	LITTLE GOOSE	2018	2058	9,899	9,899	.05949	R	9,899
	COLUMBIA BASIN	2018	2058	215,990	215,990	.05949	R	215,990
	HUNGRY HORSE	2023	2058	3,770	3,770	.05949	R	3,770
	GREEN PETER-FOSTER	2013	2058	1,921	1,921	.05949	R	1,921
	LOWER GRANITE	2018	2058	8,716	8,716	.05949	R	8,716
	CHIEF JOSEPH	2018	2058	50,163	50,163	.05949	R	50,163
	LOWER MONUMENTAL	2019	2059	7,742	7,742	.05949	R	7,742
	DETROIT-BIG CLIFF	2024	2059	2,817	2,817	.05949	R	2,817
	JOHN DAY	2015	2060	32,467	32,467	.05949	R	32,467
	MCNARY	2025	2060	71,147	71,147	.05949	R	71,147
	ALBENI FALLS	2025	2060	9,661	9,661	.05949	R	9,661
	BONNEVILLE	2021	2061	73,022	73,022	.05949	R	58,178

YEAR ------------------------------INVESTMENT PAID------------------------------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	TOTAL							603,371
2026	BONNEVILLE	2021	2026	72,812	72,812	.05488	R	72,812
	DETROIT-BIG CLIFF	2018	2026	5	5	.05571	R	5
	ICE HARBOR	2018	2026	7,875	7,875	.05571	R	7,875
	JOHN DAY	2019	2026	31	31	.05554	R	31
	DETROIT-BIG CLIFF	2014	2026	27	27	.05641	R	27
	JOHN DAY	2018	2026	5	5	.05571	R	5
	LIBBY	2016	2026	77	77	.05607	R	77
	YAKIMA-CHANDLER	2016	2026	67	67	.05607	R	67
	BONNEVILLE	2021	2061	73,022	14,844	.05949	R	14,844
	YAKIMA-CHANDLER	2026	2061	540	540	.05949	R	540
	BOISE	2017	2062	861	861	.05949	R	861
	ICE HARBOR	2012	2062	4,428	4,428	.05949	R	4,428
	BONNEVILLE	2022	2062	70,689	70,689	.05949	R	70,689
	LOWER SNAKE F AND W	2023	2063	8,084	8,084	.05949	R	8,084
	THE DALLES	2018	2063	6,548	6,548	.05949	R	6,548
	LIBBY	2025	2065	8,868	8,868	.05949	R	8,868
	ICE HARBOR	2021	2066	31	31	.05949	R	31
	LOST CREEK	2022	2067	1,362	1,362	.05949	R	1,362
	MINIDOKA	2017	2067	5,402	5,402	.05949	R	5,402
	BONNEVILLE	2022	2067	65,325	65,325	.05949	R	65,325
	COLUMBIA BASIN	2023	2068	67,373	67,373	.05949	R	67,373
	LITTLE GOOSE	2023	2068	142	142	.05949	R	142
	LOWER MONUMENTAL	2024	2069	127	127	.05949	R	127
	LOWER MONUMENTAL	2019	2069	4,636	4,636	.05949	R	4,636
	LITTLE GOOSE	2021	2071	4,014	4,014	.05949	R	4,014
	DWORSHAK	2023	2073	1,966	1,966	.05949	R	1,966
	LOWER GRANITE	2025	2075	1,782	1,782	.05949	R	1,782
	ICE HARBOR	2026	2076	1,401	1,401	.05949	R	1,401
	LIBBY	2026	2076	3,761	3,761	.05949	R	3,761
	COLUMBIA BASIN	2003	2028	507	507	.05930		507
	COLUMBIA BASIN	2004	2029	507	507	.05930		507
	COLUMBIA BASIN	2005	2030	507	507	.05910		507
	HILLS CREEK	2012	2037	1	1	.05864	R	1
	ICE HARBOR	2012	2037	1,783	1,783	.05864	R	1,783
	COUGAR	2014	2039	151	151	.05864	R	151
	BONNEVILLE	2016	2041	2,922	2,922	.05864	R	2,922
	GREEN PETER-FOSTER	2017	2042	151	151	.05864	R	151

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
MINIDOKA	2017	2042	2,215	2,215	.05864	R	2,215
GREEN PETER-FOSTER	2018	2043	77	77	.05864	R	77
LOWER MONUMENTAL	2019	2044	961	961	.05864	R	961
JOHN DAY	2020	2045	731	731	.05864	R	731
LITTLE GOOSE	2021	2046	1,100	1,100	.05864	R	1,100
COLUMBIA BASIN	2022	2047	50,909	50,909	.05864	R	50,909
DWORSHAK	2023	2048	8,301	8,301	.05864	R	8,301
LOWER GRANITE	2025	2050	234	234	.05864	R	234
ICE HARBOR	2026	2051	48	48	.05864	R	48
LIBBY	2026	2051	2,960	2,960	.05864	R	2,960
COLUMBIA BASIN	2006	2031	507	507	.05860		507
LITTLE GOOSE	2011	2031	33,953	33,953	.05778	R	33,953
DWORSHAK	2013	2033	3,845	3,845	.05778	R	3,845
HUNGRY HORSE	2013	2033	795	795	.05778	R	795
THE DALLES	2013	2033	254	254	.05778	R	254
DETROIT-BIG CLIFF	2014	2034	5,164	5,164	.05778	R	5,164
DETROIT-BIG CLIFF	2014	2034	334	334	.05778	R	334
MCNARY	2015	2035	1,392	1,392	.05778	R	1,392
LOWER GRANITE	2015	2035	40,279	40,279	.05778	R	40,279
LOOKOUT POINT-DEXTER	2015	2035	497	497	.05778	R	497
ALBENI FALLS	2015	2035	1,052	1,052	.05778	R	1,052
LOOKOUT POINT-DEXTER	2015	2035	85	85	.05778	R	85
ICE HARBOR	2016	2036	219	219	.05778	R	219
LIBBY	2016	2036	750	750	.05778	R	750
YAKIMA-CHANDLER	2016	2036	99	99	.05778	R	99
MINIDOKA	2017	2037	106	106	.05778	R	106
CHIEF JOSEPH	2017	2037	2,457	2,457	.05778	R	2,457
MINIDOKA	2017	2037	314	314	.05778	R	314
LOST CREEK	2017	2037	43	43	.05778	R	43
LOWER GRANITE	2018	2038	352	352	.05778	R	352
COLUMBIA BASIN	2018	2038	6,192	6,192	.05778	R	6,192
YAKIMA-ROZA	2018	2038	9	9	.05778	R	9
CHIEF JOSEPH	2018	2038	798	798	.05778	R	798
LITTLE GOOSE	2018	2038	218	218	.05778	R	218
LOWER MONUMENTAL	2019	2039	349	349	.05778	R	349
THE DALLES	2019	2039	1,406	1,406	.05778	R	1,406
BONNEVILLE	2021	2041	700	700	.05778	R	700
ICE HARBOR	2022	2042	1,634	1,634	.05778	R	1,634
LOWER SNAKE F AND W	2023	2043	5,870	5,870	.05778	R	5,870

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	COUGAR	2024	2044	80	80	.05778	R	80
	BONNEVILLE	2012	2027	1,251	1,251	.05692	R	1,251
	LOWER SNAKE F AND W	2013	2028	1,263	1,263	.05692	R	1,263
	HUNGRY HORSE	2013	2028	529	529	.05692	R	529
	DETROIT-BIG CLIFF	2014	2029	19	19	.05692	R	19
	LOWER MONUMENTAL	2014	2029	33,179	33,179	.05692	R	33,179
	DETROIT-BIG CLIFF	2014	2029	26,466	26,466	.05692	R	26,466
	JOHN DAY	2015	2030	2,241	2,241	.05692	R	2,241
	LIBBY	2015	2030	234	234	.05692	R	234
	JOHN DAY	2015	2030	178	178	.05692	R	178
	ALBENI FALLS	2015	2030	66	66	.05692	R	66
	LOOKOUT POINT-DEXTER	2015	2030	489	489	.05692	R	489
	MCNARY	2015	2030	23,884	23,884	.05692	R	23,884
	YAKIMA-CHANDLER	2016	2031	28	28	.05692	R	28
	BONNEVILLE	2016	2031	2,903	2,903	.05692	R	2,903
	LITTLE GOOSE	2016	2031	34,470	34,470	.05692	R	33,597
	TOTAL							663,228
2027	LOOKOUT POINT-DEXTER	2015	2027	44	44	.05641	R	44
	LITTLE GOOSE	2020	2027	26	26	.05554	R	26
	COUGAR	2020	2027	3	3	.05554	R	3
	ALBENI FALLS	2015	2027	148	148	.05641	R	148
	ICE HARBOR	2022	2027	15,363	15,363	.05488	R	15,363
	MCNARY	2015	2027	32,275	32,275	.05641	R	32,275
	LITTLE GOOSE	2019	2027	45	45	.05571	R	45
	MINIDOKA	2017	2027	18	18	.05607	R	18
	LOOKOUT POINT-DEXTER	2019	2027	6	6	.05571	R	6
	MCNARY	2019	2027	67	67	.05571	R	67
	GREEN PETER-FOSTER	2017	2027	25	25	.05607	R	25
	CHIEF JOSEPH	2017	2027	46	46	.05607	R	46
	GREEN PETER-FOSTER	2027	2057	501	501	.05949	R	501
	CHIEF JOSEPH	2027	2062	64,683	64,683	.05949	R	64,683
	MINIDOKA	2027	2062	835	835	.05949	R	835
	COLUMBIA BASIN	2027	2067	49,177	49,177	.05949	R	49,177
	BONNEVILLE	2027	2072	1,082	1,082	.05949	R	1,082
	BONNEVILLE	2027	2077	336	336	.05949	R	336
	BOISE	2027	2077	8,883	8,883	.05949	R	8,883
	LOST CREEK	2027	2077	653	653	.05949	R	653
	BONNEVILLE	2027	2052	15	15	.05864	R	15

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
BOISE	2027	2052	24,348	24,348	.05864	R	24,348
LOST CREEK	2027	2052	84	84	.05864	R	84
BOISE	2027	2047	159	159	.05778	R	159
GREEN PETER-FOSTER	2027	2047	1,093	1,093	.05778	R	1,093
COLUMBIA BASIN	2027	2047	5,285	5,285	.05778	R	5,285
LITTLE GOOSE	2016	2031	34,470	873	.05692	R	873
MINIDOKA	2017	2032	143	143	.05692	R	143
CHIEF JOSEPH	2017	2032	1,607	1,607	.05692	R	1,607
BOISE	2017	2032	14	14	.05692	R	14
THE DALLES	2018	2033	2,205	2,205	.05692	R	2,205
YAKIMA-ROZA	2018	2033	3	3	.05692	R	3
DWORSHAK	2018	2033	3,295	3,295	.05692	R	3,295
THE DALLES	2019	2034	1,429	1,429	.05692	R	1,429
LOWER GRANITE	2020	2035	19,623	19,623	.05692	R	19,623
LIBBY	2021	2036	2,135	2,135	.05692	R	2,135
COLUMBIA BASIN	2022	2037	953	953	.05692	R	953
MINIDOKA	2022	2037	97	97	.05692	R	97
CHIEF JOSEPH	2023	2038	227	227	.05692	R	227
LOWER GRANITE	2023	2038	352	352	.05692	R	352
COLUMBIA BASIN	2023	2038	1,288	1,288	.05692	R	1,288
COUGAR	2024	2039	49	49	.05692	R	49
BONNEVILLE	2027	2042	1,251	1,251	.05692	R	1,251
LOWER MONUMENTAL	2017	2029	2,582	2,582	.05641	R	2,582
JOHN DAY	2018	2030	49	49	.05641	R	49
LITTLE GOOSE	2019	2031	2,582	2,582	.05641	R	2,582
LOWER SNAKE F AND W	2019	2031	586	586	.05641	R	586
THE DALLES	2019	2031	10	10	.05641	R	10
DWORSHAK	2021	2033	61	61	.05641	R	61
THE DALLES	2021	2033	1,949	1,949	.05641	R	1,949
ICE HARBOR	2022	2034	5,422	5,422	.05641	R	5,422
LOWER GRANITE	2023	2035	23	23	.05641	R	23
BONNEVILLE	2025	2037	164	164	.05641	R	164
LOST CREEK	2025	2037	5	5	.05641	R	5
DETROIT-BIG CLIFF	2026	2038	27	27	.05641	R	27
LOOKOUT POINT-DEXTER	2027	2039	44	44	.05641	R	44
MCNARY	2027	2039	32,275	32,275	.05641	R	32,275
ALBENI FALLS	2027	2039	148	148	.05641	R	148
LITTLE GOOSE	2018	2028	1,171	1,171	.05607	R	1,171
LOWER MONUMENTAL	2019	2029	13	13	.05607	R	13

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
THE DALLES	2019	2029	1	1	.05607	R	1
LITTLE GOOSE	2021	2031	13	13	.05607	R	13
BONNEVILLE	2021	2031	127	127	.05607	R	127
ICE HARBOR	2022	2032	14,976	14,976	.05607	R	14,976
LOWER SNAKE F AND W	2023	2033	1,168	1,168	.05607	R	1,168
DWORSHAK	2023	2033	207	207	.05607	R	207
DETROIT-BIG CLIFF	2024	2034	36	36	.05607	R	36
LOOKOUT POINT-DEXTER	2025	2035	123	123	.05607	R	123
MCNARY	2025	2035	65,841	65,841	.05607	R	65,841
LOWER GRANITE	2025	2035	1,003	1,003	.05607	R	1,003
ALBENI FALLS	2025	2035	1	1	.05607	R	1
LIBBY	2026	2036	77	77	.05607	R	77
YAKIMA-CHANDLER	2026	2036	67	67	.05607	R	67
CHIEF JOSEPH	2027	2037	46	46	.05607	R	46
GREEN PETER-FOSTER	2027	2037	25	25	.05607	R	25
MINIDOKA	2027	2037	18	18	.05607	R	18
COUGAR	2020	2028	4	4	.05571	R	4
DWORSHAK	2021	2029	43	43	.05571	R	43
BONNEVILLE	2021	2029	4,519	4,519	.05571	R	4,519
LOWER GRANITE	2023	2031	36	36	.05571	R	36
LOWER SNAKE F AND W	2023	2031	123	123	.05571	R	123
THE DALLES	2023	2031	80	80	.05571	R	80
GREEN PETER-FOSTER	2023	2031	15	15	.05571	R	15
LOWER MONUMENTAL	2025	2033	50	50	.05571	R	50
LOST CREEK	2025	2033	1	1	.05571	R	1
ICE HARBOR	2026	2034	7,875	7,875	.05571	R	7,875
DETROIT-BIG CLIFF	2026	2034	5	5	.05571	R	5
JOHN DAY	2026	2034	5	5	.05571	R	5
MCNARY	2027	2035	67	67	.05571	R	67
LOOKOUT POINT-DEXTER	2027	2035	6	6	.05571	R	6
LITTLE GOOSE	2027	2035	45	45	.05571	R	45
DWORSHAK	2022	2029	19	19	.05554	R	19
THE DALLES	2022	2029	53	53	.05554	R	53
GREEN PETER-FOSTER	2023	2030	19	19	.05554	R	19
LOWER GRANITE	2024	2031	27	27	.05554	R	27
DETROIT-BIG CLIFF	2024	2031	3	3	.05554	R	3
LOWER SNAKE F AND W	2025	2032	642	642	.05554	R	642
BONNEVILLE	2025	2032	30,984	30,984	.05554	R	30,984
LIBBY	2025	2032	77	77	.05554	R	77

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LOOKOUT POINT-DEXTER	2025	2032	17	17	.05554	R	17
	ICE HARBOR	2025	2032	29,048	29,048	.05554	R	29,048
	MCNARY	2025	2032	32	32	.05554	R	32
	LOWER MONUMENTAL	2025	2032	26	26	.05554	R	26
	JOHN DAY	2026	2033	31	31	.05554	R	31
	LITTLE GOOSE	2027	2034	26	26	.05554	R	26
	COUGAR	2027	2034	3	3	.05554	R	3
	LOWER SNAKE F AND W	2023	2028	54	54	.05488	R	54
	THE DALLES	2024	2029	49	49	.05488	R	49
	BONNEVILLE	2026	2031	72,812	72,812	.05488	R	72,812
	ICE HARBOR	2027	2032	15,363	15,363	.05488	R	15,363
	BONNEVILLE	1999	2044	29,984	29,984	.05325		29,984
	COLUMBIA RIVER FISH MITIGATION	1999	2049	20,689	20,689	.05325		20,689
	TOTAL							584,416
2028	GREEN PETER-FOSTER	2028	2058	181	181	.05949	R	181
	YAKIMA-ROZA	2028	2063	62	62	.05949	R	62
	LOWER SNAKE F AND W	2028	2073	1,207	1,207	.05949	R	1,207
	LOWER GRANITE	2028	2078	1,860	1,860	.05949	R	1,860
	LITTLE GOOSE	2028	2078	1,921	1,921	.05949	R	1,921
	COLUMBIA BASIN	2028	2078	131,228	131,228	.05949	R	131,228
	CHIEF JOSEPH	2028	2078	13,873	13,873	.05949	R	13,873
	LITTLE GOOSE	2028	2053	43	43	.05864	R	43
	HUNGRY HORSE	2028	2053	12,103	12,103	.05864	R	12,103
	LOWER GRANITE	2028	2053	132	132	.05864	R	132
	COLUMBIA BASIN	2028	2053	55,867	55,867	.05864	R	55,867
	CHIEF JOSEPH	2028	2053	385	385	.05864	R	385
	GREEN PETER-FOSTER	2028	2048	893	893	.05778	R	893
	HUNGRY HORSE	2028	2043	529	529	.05692	R	529
	LOWER SNAKE F AND W	2028	2043	1,263	1,263	.05692	R	1,263
	LITTLE GOOSE	2028	2038	1,171	1,171	.05607	R	1,171
	COUGAR	2028	2036	4	4	.05571	R	4
	LOWER SNAKE F AND W	2028	2033	54	54	.05488	R	54
	TOTAL							222,776

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2029	LOWER MONUMENTAL	2029	2059	278	278	.05949	R	278
	THE DALLES	2029	2064	79,074	79,074	.05949	R	79,074
	LOWER MONUMENTAL	2029	2079	1,882	1,882	.05949	R	1,882
	LOWER MONUMENTAL	2029	2054	45	45	.05864	R	45
	DETROIT-BIG CLIFF	2029	2054	234	234	.05864	R	234
	DETROIT-BIG CLIFF	2029	2054	120	120	.05864	R	120
	LOWER MONUMENTAL	2029	2049	33,953	33,953	.05778	R	33,953
	LOWER MONUMENTAL	2029	2044	33,179	33,179	.05692	R	33,179
	DETROIT-BIG CLIFF	2029	2044	26,466	26,466	.05692	R	26,466
	DETROIT-BIG CLIFF	2029	2044	19	19	.05692	R	19
	LOWER MONUMENTAL	2029	2041	2,582	2,582	.05641	R	2,582
	LOWER MONUMENTAL	2029	2039	13	13	.05607	R	13
	THE DALLES	2029	2039	1	1	.05607	R	1
	DWORSHAK	2029	2037	43	43	.05571	R	43
	BONNEVILLE	2029	2037	4,519	4,519	.05571	R	4,519
	DWORSHAK	2029	2036	19	19	.05554	R	19
	THE DALLES	2029	2036	53	53	.05554	R	53
	THE DALLES	2029	2034	49	49	.05488	R	49
	TOTAL							182,529
2030	JOHN DAY	2030	2060	3,998	3,998	.05949	R	3,998
	MCNARY	2030	2055	1,029	1,029	.05864	R	1,029
	LOOKOUT POINT-DEXTER	2030	2055	605	605	.05864	R	605
	LOOKOUT POINT-DEXTER	2030	2055	39	39	.05864	R	39
	ALBENI FALLS	2030	2055	2,866	2,866	.05864	R	2,866
	JOHN DAY	2030	2050	2,241	2,241	.05778	R	2,241
	MCNARY	2030	2045	23,884	23,884	.05692	R	23,884
	JOHN DAY	2030	2045	178	178	.05692	R	178
	LIBBY	2030	2045	234	234	.05692	R	234
	JOHN DAY	2030	2045	2,241	2,241	.05692	R	2,241
	ALBENI FALLS	2030	2045	66	66	.05692	R	66
	LOOKOUT POINT-DEXTER	2030	2045	489	489	.05692	R	489
	JOHN DAY	2030	2042	49	49	.05641	R	49
	GREEN PETER-FOSTER	2030	2037	19	19	.05554	R	19
	TOTAL							37,938

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2031	LITTLE GOOSE	2031	2061	272	272	.05949	R	272
	BONNEVILLE	2031	2076	1,257	1,257	.05949	R	1,257
	YAKIMA-CHANDLER	2031	2056	1,062	1,062	.05864	R	1,062
	LITTLE GOOSE	2031	2051	33,953	33,953	.05778	R	33,953
	LITTLE GOOSE	2031	2046	34,470	34,470	.05692	R	34,470
	YAKIMA-CHANDLER	2031	2046	28	28	.05692	R	28
	BONNEVILLE	2031	2046	2,903	2,903	.05692	R	2,903
	LOWER SNAKE F AND W	2031	2043	586	586	.05641	R	586
	LITTLE GOOSE	2031	2043	2,582	2,582	.05641	R	2,582
	THE DALLES	2031	2043	10	10	.05641	R	10
	LITTLE GOOSE	2031	2041	13	13	.05607	R	13
	BONNEVILLE	2031	2041	127	127	.05607	R	127
	GREEN PETER-FOSTER	2031	2039	15	15	.05571	R	15
	LOWER SNAKE F AND W	2031	2039	123	123	.05571	R	123
	LOWER GRANITE	2031	2039	36	36	.05571	R	36
	THE DALLES	2031	2039	80	80	.05571	R	80
	DETROIT-BIG CLIFF	2031	2038	3	3	.05554	R	3
	LOWER GRANITE	2031	2038	27	27	.05554	R	27
	BONNEVILLE	2031	2036	72,812	72,812	.05488	R	72,812
	TOTAL							150,359
2032	ICE HARBOR	2032	2067	18,944	18,944	.05949	R	18,944
	BOISE	2032	2067	1,096	1,096	.05949	R	1,096
	BONNEVILLE	2032	2082	15,322	15,322	.05949	R	15,322
	MINIDOKA	2032	2057	2,648	2,648	.05864	R	2,648
	CHIEF JOSEPH	2032	2057	4,722	4,722	.05864	R	4,722
	BONNEVILLE	2032	2057	4,800	4,800	.05864	R	4,800
	CHIEF JOSEPH	2032	2047	1,607	1,607	.05692	R	1,607
	MINIDOKA	2032	2047	143	143	.05692	R	143
	BOISE	2032	2047	14	14	.05692	R	14
	ICE HARBOR	2032	2042	14,976	14,976	.05607	R	14,976
	LOWER SNAKE F AND W	2032	2039	642	642	.05554	R	642
	LIBBY	2032	2039	77	77	.05554	R	77
	LOWER MONUMENTAL	2032	2039	26	26	.05554	R	26
	LOOKOUT POINT-DEXTER	2032	2039	17	17	.05554	R	17
	BONNEVILLE	2032	2039	30,984	30,984	.05554	R	30,984
	MCNARY	2032	2039	32	32	.05554	R	32
	ICE HARBOR	2032	2039	29,048	29,048	.05554	R	29,048
	ICE HARBOR	2032	2037	15,363	15,363	.05488	R	15,363

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	TOTAL							140,461
2033	THE DALLES	2033	2063	21,796	21,796	.05949	R	21,796
	HUNGRY HORSE	2033	2073	6,916	6,916	.05949	R	6,916
	LOWER SNAKE F AND W	2033	2083	18,862	18,862	.05949	R	18,862
	YAKIMA-ROZA	2033	2058	120	120	.05864	R	120
	LOWER SNAKE F AND W	2033	2058	1,135	1,135	.05864	R	1,135
	THE DALLES	2033	2053	254	254	.05778	R	254
	HUNGRY HORSE	2033	2053	795	795	.05778	R	795
	DWORSHAK	2033	2053	3,845	3,845	.05778	R	3,845
	YAKIMA-ROZA	2033	2048	3	3	.05692	R	3
	DWORSHAK	2033	2048	3,295	3,295	.05692	R	3,295
	THE DALLES	2033	2048	2,205	2,205	.05692	R	2,205
	THE DALLES	2033	2045	1,949	1,949	.05641	R	1,949
	DWORSHAK	2033	2045	61	61	.05641	R	61
	LOWER SNAKE F AND W	2033	2043	1,168	1,168	.05607	R	1,168
	DWORSHAK	2033	2043	207	207	.05607	R	207
	LOST CREEK	2033	2041	1	1	.05571	R	1
	LOWER MONUMENTAL	2033	2041	50	50	.05571	R	50
	JOHN DAY	2033	2040	31	31	.05554	R	31
	LOWER SNAKE F AND W	2033	2038	54	54	.05488	R	54
	TOTAL							62,747
2034	COUGAR	2034	2069	2,903	2,903	.05949	R	2,903
	DETROIT-BIG CLIFF	2034	2074	14,517	14,517	.05949	R	14,517
	DETROIT-BIG CLIFF	2034	2074	1,690	1,690	.05949	R	1,690
	THE DALLES	2034	2059	2,887	2,887	.05864	R	2,887
	DETROIT-BIG CLIFF	2034	2054	334	334	.05778	R	334
	DETROIT-BIG CLIFF	2034	2054	5,164	5,164	.05778	R	5,164
	THE DALLES	2034	2049	1,429	1,429	.05692	R	1,429
	ICE HARBOR	2034	2046	5,422	5,422	.05641	R	5,422
	DETROIT-BIG CLIFF	2034	2044	36	36	.05607	R	36
	DETROIT-BIG CLIFF	2034	2042	5	5	.05571	R	5
	JOHN DAY	2034	2042	5	5	.05571	R	5
	ICE HARBOR	2034	2042	7,875	7,875	.05571	R	7,875
	LITTLE GOOSE	2034	2041	26	26	.05554	R	26
	COUGAR	2034	2041	3	3	.05554	R	3
	THE DALLES	2034	2039	49	49	.05488	R	49
	TOTAL							42,345

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2035	LOWER GRANITE	2035	2065	753	753	.05949	R	753
	MCNARY	2035	2075	36,506	36,506	.05949	R	36,506
	LOOKOUT POINT-DEXTER	2035	2075	2,399	2,399	.05949	R	2,399
	LOOKOUT POINT-DEXTER	2035	2075	12,028	12,028	.05949	R	12,028
	ALBENI FALLS	2035	2075	723	723	.05949	R	723
	LIBBY	2035	2085	6,842	6,842	.05949	R	6,842
	LIBBY	2035	2060	315	315	.05864	R	315
	LOOKOUT POINT-DEXTER	2035	2055	497	497	.05778	R	497
	MCNARY	2035	2055	1,392	1,392	.05778	R	1,392
	LOOKOUT POINT-DEXTER	2035	2055	85	85	.05778	R	85
	ALBENI FALLS	2035	2055	1,052	1,052	.05778	R	1,052
	LOWER GRANITE	2035	2055	40,279	40,279	.05778	R	40,279
	LOWER GRANITE	2035	2050	19,623	19,623	.05692	R	19,623
	LOWER GRANITE	2035	2047	23	23	.05641	R	23
	LOOKOUT POINT-DEXTER	2035	2045	123	123	.05607	R	123
	MCNARY	2035	2045	65,841	65,841	.05607	R	65,841
	LOWER GRANITE	2035	2045	1,003	1,003	.05607	R	1,003
	ALBENI FALLS	2035	2045	1	1	.05607	R	1
	LITTLE GOOSE	2035	2043	45	45	.05571	R	45
	LOOKOUT POINT-DEXTER	2035	2043	6	6	.05571	R	6
	MCNARY	2035	2043	67	67	.05571	R	67
	TOTAL							189,603
2036	YAKIMA-CHANDLER	2036	2076	533	533	.05949	R	533
	YAKIMA-CHANDLER	2036	2056	99	99	.05778	R	99
	LIBBY	2036	2056	750	750	.05778	R	750
	ICE HARBOR	2036	2056	219	219	.05778	R	219
	LIBBY	2036	2051	2,135	2,135	.05692	R	2,135
	YAKIMA-CHANDLER	2036	2046	67	67	.05607	R	67
	LIBBY	2036	2046	77	77	.05607	R	77
	COUGAR	2036	2044	4	4	.05571	R	4
	DWORSHAK	2036	2043	19	19	.05554	R	19
	THE DALLES	2036	2043	53	53	.05554	R	53
	BONNEVILLE	2036	2041	72,812	72,812	.05488	R	72,812
	TOTAL							76,768

YEAR ------INVESTMENT PAID------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2037	MINIDOKA	2037	2067	79	79	.05949	R	79
	LOST CREEK	2037	2067	185	185	.05949	R	185
	COLUMBIA BASIN	2037	2067	2,360	2,360	.05949	R	2,360
	MINIDOKA	2037	2077	1,850	1,850	.05949	R	1,850
	MINIDOKA	2037	2077	7,133	7,133	.05949	R	7,133
	CHIEF JOSEPH	2037	2077	31,147	31,147	.05949	R	31,147
	COLUMBIA BASIN	2037	2082	52,195	52,195	.05949	R	52,195
	ICE HARBOR	2037	2062	1,783	1,783	.05864	R	1,783
	HILLS CREEK	2037	2062	1	1	.05864	R	1
	LOST CREEK	2037	2057	43	43	.05778	R	43
	MINIDOKA	2037	2057	106	106	.05778	R	106
	MINIDOKA	2037	2057	314	314	.05778	R	314
	CHIEF JOSEPH	2037	2057	2,457	2,457	.05778	R	2,457
	COLUMBIA BASIN	2037	2052	953	953	.05692	R	953
	MINIDOKA	2037	2052	97	97	.05692	R	97
	LOST CREEK	2037	2049	5	5	.05641	R	5
	BONNEVILLE	2037	2049	164	164	.05641	R	164
	GREEN PETER-FOSTER	2037	2047	25	25	.05607	R	25
	MINIDOKA	2037	2047	18	18	.05607	R	18
	CHIEF JOSEPH	2037	2047	46	46	.05607	R	46
	DWORSHAK	2037	2045	43	43	.05571	R	43
	BONNEVILLE	2037	2045	4,519	4,519	.05571	R	4,519
	GREEN PETER-FOSTER	2037	2044	19	19	.05554	R	19
	ICE HARBOR	2037	2042	15,363	15,363	.05488	R	15,363
	TOTAL							120,905
2038	COLUMBIA BASIN	2038	2068	2,649	2,649	.05949	R	2,649
	YAKIMA-ROZA	2038	2078	141	141	.05949	R	141
	LOWER GRANITE	2038	2058	352	352	.05778	R	352
	LITTLE GOOSE	2038	2058	218	218	.05778	R	218
	YAKIMA-ROZA	2038	2058	9	9	.05778	R	9
	COLUMBIA BASIN	2038	2058	6,192	6,192	.05778	R	6,192
	CHIEF JOSEPH	2038	2058	798	798	.05778	R	798
	LOWER GRANITE	2038	2053	352	352	.05692	R	352
	COLUMBIA BASIN	2038	2053	1,288	1,288	.05692	R	1,288
	CHIEF JOSEPH	2038	2053	227	227	.05692	R	227
	DETROIT-BIG CLIFF	2038	2050	27	27	.05641	R	27
	LITTLE GOOSE	2038	2048	1,171	1,171	.05607	R	1,171
	DETROIT-BIG CLIFF	2038	2045	3	3	.05554	R	3

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LOWER GRANITE	2038	2045	27	27	.05554	R	27
	LOWER SNAKE F AND W	2038	2043	54	54	.05488	R	54
	TOTAL							13,508
2039	LOWER MONUMENTAL	2039	2074	11,593	11,593	.05949	R	11,593
	THE DALLES	2039	2079	49,926	49,926	.05949	R	49,926
	COUGAR	2039	2064	151	151	.05864	R	151
	LOWER MONUMENTAL	2039	2059	349	349	.05778	R	349
	THE DALLES	2039	2059	1,406	1,406	.05778	R	1,406
	COUGAR	2039	2054	49	49	.05692	R	49
	LOOKOUT POINT-DEXTER	2039	2051	44	44	.05641	R	44
	MCNARY	2039	2051	32,275	32,275	.05641	R	32,275
	ALBENI FALLS	2039	2051	148	148	.05641	R	148
	THE DALLES	2039	2049	1	1	.05607	R	1
	LOWER MONUMENTAL	2039	2049	13	13	.05607	R	13
	THE DALLES	2039	2047	80	80	.05571	R	80
	LOWER GRANITE	2039	2047	36	36	.05571	R	36
	GREEN PETER-FOSTER	2039	2047	15	15	.05571	R	15
	LOWER SNAKE F AND W	2039	2047	123	123	.05571	R	123
	LOOKOUT POINT-DEXTER	2039	2046	17	17	.05554	R	17
	LIBBY	2039	2046	77	77	.05554	R	77
	ICE HARBOR	2039	2046	29,048	29,048	.05554	R	29,048
	LOWER MONUMENTAL	2039	2046	26	26	.05554	R	26
	MCNARY	2039	2046	32	32	.05554	R	32
	BONNEVILLE	2039	2046	30,984	30,984	.05554	R	30,984
	LOWER SNAKE F AND W	2039	2046	642	642	.05554	R	642
	THE DALLES	2039	2044	49	49	.05488	R	49
	TOTAL							157,084
2040	JOHN DAY	2040	2075	608	608	.05949	R	608
	JOHN DAY	2040	2047	31	31	.05554	R	31
	TOTAL							639

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2041	LITTLE GOOSE	2041	2076	14,147	14,147	.05949	R	14,147
	DETROIT-BIG CLIFF	2041	2091	636	636	.05949	R	636
	BONNEVILLE	2041	2091	24,277	24,277	.05949	R	24,277
	BONNEVILLE	2041	2066	2,922	2,922	.05864	R	2,922
	BONNEVILLE	2041	2061	700	700	.05778	R	700
	LOWER MONUMENTAL	2041	2053	2,582	2,582	.05641	R	2,582
	BONNEVILLE	2041	2051	127	127	.05607	R	127
	LITTLE GOOSE	2041	2051	13	13	.05607	R	13
	LOST CREEK	2041	2049	1	1	.05571	R	1
	LOWER MONUMENTAL	2041	2049	50	50	.05571	R	50
	LITTLE GOOSE	2041	2048	26	26	.05554	R	26
	COUGAR	2041	2048	3	3	.05554	R	3
	BONNEVILLE	2041	2046	72,812	72,812	.05488	R	72,812
	TOTAL							118,296
2042	ICE HARBOR	2042	2082	13,042	13,042	.05949	R	13,042
	HILLS CREEK	2042	2082	1,986	1,986	.05949	R	1,986
	MINIDOKA	2042	2067	2,215	2,215	.05864	R	2,215
	GREEN PETER-FOSTER	2042	2067	151	151	.05864	R	151
	ICE HARBOR	2042	2062	1,634	1,634	.05778	R	1,634
	BONNEVILLE	2042	2057	1,251	1,251	.05692	R	1,251
	JOHN DAY	2042	2054	49	49	.05641	R	49
	ICE HARBOR	2042	2052	14,976	14,976	.05607	R	14,976
	ICE HARBOR	2042	2050	7,875	7,875	.05571	R	7,875
	JOHN DAY	2042	2050	5	5	.05571	R	5
	DETROIT-BIG CLIFF	2042	2050	5	5	.05571	R	5
	ICE HARBOR	2042	2047	15,363	15,363	.05488	R	15,363
	TOTAL							58,552
2043	LOWER SNAKE F AND W	2043	2073	2,493	2,493	.05949	R	2,493
	HUNGRY HORSE	2043	2073	534	534	.05949	R	534
	THE DALLES	2043	2078	17,626	17,626	.05949	R	17,626
	DWORSHAK	2043	2078	13,957	13,957	.05949	R	13,957
	HUNGRY HORSE	2043	2088	7,596	7,596	.05949	R	7,596
	GREEN PETER-FOSTER	2043	2068	77	77	.05864	R	77
	LOWER SNAKE F AND W	2043	2063	5,870	5,870	.05778	R	5,870
	HUNGRY HORSE	2043	2058	529	529	.05692	R	529
	LOWER SNAKE F AND W	2043	2058	1,263	1,263	.05692	R	1,263
	LOWER SNAKE F AND W	2043	2055	586	586	.05641	R	586

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LITTLE GOOSE	2043	2055	2,582	2,582	.05641	R	2,582
	THE DALLES	2043	2055	10	10	.05641	R	10
	LOWER SNAKE F AND W	2043	2053	1,168	1,168	.05607	R	1,168
	DWORSHAK	2043	2053	207	207	.05607	R	207
	LITTLE GOOSE	2043	2051	45	45	.05571	R	45
	MCNARY	2043	2051	67	67	.05571	R	67
	LOOKOUT POINT-DEXTER	2043	2051	6	6	.05571	R	6
	DWORSHAK	2043	2050	19	19	.05554	R	19
	THE DALLES	2043	2050	53	53	.05554	R	53
	LOWER SNAKE F AND W	2043	2048	54	54	.05488	R	54
	TOTAL							54,742
2044	DETROIT-BIG CLIFF	2044	2074	698	698	.05949	R	698
	COUGAR	2044	2084	1,711	1,711	.05949	R	1,711
	DETROIT-BIG CLIFF	2044	2089	5,518	5,518	.05949	R	5,518
	LOWER MONUMENTAL	2044	2069	961	961	.05864	R	961
	COUGAR	2044	2064	80	80	.05778	R	80
	DETROIT-BIG CLIFF	2044	2059	26,466	26,466	.05692	R	26,466
	DETROIT-BIG CLIFF	2044	2059	19	19	.05692	R	19
	LOWER MONUMENTAL	2044	2059	33,179	33,179	.05692	R	33,179
	DETROIT-BIG CLIFF	2044	2054	36	36	.05607	R	36
	COUGAR	2044	2052	4	4	.05571	R	4
	GREEN PETER-FOSTER	2044	2051	19	19	.05554	R	19
	THE DALLES	2044	2049	49	49	.05488	R	49
	TOTAL							68,740
2045	LOWER GRANITE	2045	2080	9,529	9,529	.05949	R	9,529
	LOOKOUT POINT-DEXTER	2045	2090	2,612	2,612	.05949	R	2,612
	LOOKOUT POINT-DEXTER	2045	2090	6,285	6,285	.05949	R	6,285
	JOHN DAY	2045	2070	731	731	.05864	R	731
	LOOKOUT POINT-DEXTER	2045	2060	489	489	.05692	R	489
	MCNARY	2045	2060	23,884	23,884	.05692	R	23,884
	LIBBY	2045	2060	234	234	.05692	R	234
	JOHN DAY	2045	2060	178	178	.05692	R	178
	JOHN DAY	2045	2060	2,241	2,241	.05692	R	2,241
	ALBENI FALLS	2045	2060	66	66	.05692	R	66
	THE DALLES	2045	2057	1,949	1,949	.05641	R	1,949
	DWORSHAK	2045	2057	61	61	.05641	R	61
	LOWER GRANITE	2045	2055	1,003	1,003	.05607	R	1,003

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LOOKOUT POINT-DEXTER	2045	2055	123	123	.05607	R	123
	ALBENI FALLS	2045	2055	1	1	.05607	R	1
	MCNARY	2045	2055	65,841	65,841	.05607	R	65,841
	BONNEVILLE	2045	2053	4,519	4,519	.05571	R	4,519
	DWORSHAK	2045	2053	43	43	.05571	R	43
	LOWER GRANITE	2045	2052	27	27	.05554	R	27
	DETROIT-BIG CLIFF	2045	2052	3	3	.05554	R	3
	TOTAL							119,819
2046	YAKIMA-CHANDLER	2046	2076	68	68	.05949	R	68
	LIBBY	2046	2081	11,804	11,804	.05949	R	11,804
	ICE HARBOR	2046	2081	7,271	7,271	.05949	R	7,271
	BONNEVILLE	2046	2081	82,824	82,824	.05949	R	82,824
	YAKIMA-CHANDLER	2046	2091	871	871	.05949	R	871
	LITTLE GOOSE	2046	2071	1,100	1,100	.05864	R	1,100
	LITTLE GOOSE	2046	2061	34,470	34,470	.05692	R	34,470
	YAKIMA-CHANDLER	2046	2061	28	28	.05692	R	28
	BONNEVILLE	2046	2061	2,903	2,903	.05692	R	2,903
	ICE HARBOR	2046	2058	5,422	5,422	.05641	R	5,422
	LIBBY	2046	2056	77	77	.05607	R	77
	YAKIMA-CHANDLER	2046	2056	67	67	.05607	R	67
	LIBBY	2046	2053	77	77	.05554	R	77
	ICE HARBOR	2046	2053	29,048	29,048	.05554	R	29,048
	MCNARY	2046	2053	32	32	.05554	R	32
	LOWER MONUMENTAL	2046	2053	26	26	.05554	R	26
	BONNEVILLE	2046	2053	30,984	30,984	.05554	R	30,984
	LOOKOUT POINT-DEXTER	2046	2053	17	17	.05554	R	17
	LOWER SNAKE F AND W	2046	2053	642	642	.05554	R	642
	BONNEVILLE	2046	2051	72,812	72,812	.05488	R	72,812
	TOTAL							280,543
2047	MINIDOKA	2047	2077	99	99	.05949	R	99
	BOISE	2047	2077	74	74	.05949	R	74
	LOST CREEK	2047	2082	19	19	.05949	R	19
	BONNEVILLE	2047	2082	17	17	.05949	R	17
	GREEN PETER-FOSTER	2047	2087	4,324	4,324	.05949	R	4,324
	BOISE	2047	2087	904	904	.05949	R	904
	MINIDOKA	2047	2092	4,528	4,528	.05949	R	4,528
	COLUMBIA BASIN	2047	2097	158,969	158,969	.05949	R	158,969

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	COLUMBIA BASIN	2047	2072	50,909	50,909	.05864	R	50,909
	GREEN PETER-FOSTER	2047	2067	1,093	1,093	.05778	R	1,093
	COLUMBIA BASIN	2047	2067	5,285	5,285	.05778	R	5,285
	BOISE	2047	2067	159	159	.05778	R	159
	MINIDOKA	2047	2062	143	143	.05692	R	143
	CHIEF JOSEPH	2047	2062	1,607	1,607	.05692	R	1,607
	BOISE	2047	2062	14	14	.05692	R	14
	LOWER GRANITE	2047	2059	23	23	.05641	R	23
	CHIEF JOSEPH	2047	2057	46	46	.05607	R	46
	MINIDOKA	2047	2057	18	18	.05607	R	18
	GREEN PETER-FOSTER	2047	2057	25	25	.05607	R	25
	GREEN PETER-FOSTER	2047	2055	15	15	.05571	R	15
	THE DALLES	2047	2055	80	80	.05571	R	80
	LOWER SNAKE F AND W	2047	2055	123	123	.05571	R	123
	LOWER GRANITE	2047	2055	36	36	.05571	R	36
	JOHN DAY	2047	2054	31	31	.05554	R	31
	ICE HARBOR	2047	2052	15,363	15,363	.05488	R	15,363
	TOTAL							243,904
2048	YAKIMA-ROZA	2048	2078	5	5	.05949	R	5
	LOWER GRANITE	2048	2083	11,223	11,223	.05949	R	11,223
	LITTLE GOOSE	2048	2083	11,039	11,039	.05949	R	11,039
	COLUMBIA BASIN	2048	2083	61,863	61,863	.05949	R	61,863
	CHIEF JOSEPH	2048	2083	78,501	78,501	.05949	R	78,501
	GREEN PETER-FOSTER	2048	2088	18,961	18,961	.05949	R	18,961
	YAKIMA-ROZA	2048	2093	238	238	.05949	R	238
	DWORSHAK	2048	2073	8,301	8,301	.05864	R	8,301
	GREEN PETER-FOSTER	2048	2068	893	893	.05778	R	893
	YAKIMA-ROZA	2048	2063	3	3	.05692	R	3
	DWORSHAK	2048	2063	3,295	3,295	.05692	R	3,295
	THE DALLES	2048	2063	2,205	2,205	.05692	R	2,205
	LITTLE GOOSE	2048	2058	1,171	1,171	.05607	R	1,171
	COUGAR	2048	2055	3	3	.05554	R	3
	LITTLE GOOSE	2048	2055	26	26	.05554	R	26
	LOWER SNAKE F AND W	2048	2053	54	54	.05488	R	54
	TOTAL							197,781

YEAR ---INVESTMENT PAID---

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2049	LOWER MONUMENTAL	2049	2084	10,664	10,664	.05949	R	10,664
	LOWER MONUMENTAL	2049	2089	11,877	11,877	.05949	R	11,877
	LOWER MONUMENTAL	2049	2069	33,953	33,953	.05778	R	33,953
	THE DALLES	2049	2064	1,429	1,429	.05692	R	1,429
	LOST CREEK	2049	2061	5	5	.05641	R	5
	BONNEVILLE	2049	2061	164	164	.05641	R	164
	THE DALLES	2049	2059	1	1	.05607	R	1
	LOWER MONUMENTAL	2049	2059	13	13	.05607	R	13
	LOST CREEK	2049	2057	1	1	.05571	R	1
	LOWER MONUMENTAL	2049	2057	50	50	.05571	R	50
	THE DALLES	2049	2054	49	49	.05488	R	49
	TOTAL							58,206
2050	JOHN DAY	2050	2090	52,082	52,082	.05949	R	52,082
	LOWER GRANITE	2050	2075	234	234	.05864	R	234
	JOHN DAY	2050	2070	2,241	2,241	.05778	R	2,241
	LOWER GRANITE	2050	2065	19,623	19,623	.05692	R	19,623
	DETROIT-BIG CLIFF	2050	2062	27	27	.05641	R	27
	JOHN DAY	2050	2058	5	5	.05571	R	5
	ICE HARBOR	2050	2058	7,875	7,875	.05571	R	7,875
	DETROIT-BIG CLIFF	2050	2058	5	5	.05571	R	5
	DWORSHAK	2050	2057	19	19	.05554	R	19
	THE DALLES	2050	2057	53	53	.05554	R	53
	TOTAL							82,164
2051	LITTLE GOOSE	2051	2091	11,872	11,872	.05949	R	11,872
	LIBBY	2051	2076	2,960	2,960	.05864	R	2,960
	ICE HARBOR	2051	2076	48	48	.05864	R	48
	LITTLE GOOSE	2051	2071	33,953	33,953	.05778	R	33,953
	LIBBY	2051	2066	2,135	2,135	.05692	R	2,135
	MCNARY	2051	2063	32,275	32,275	.05641	R	32,275
	LOOKOUT POINT-DEXTER	2051	2063	44	44	.05641	R	44
	ALBENI FALLS	2051	2063	148	148	.05641	R	148
	LITTLE GOOSE	2051	2061	13	13	.05607	R	13
	BONNEVILLE	2051	2061	127	127	.05607	R	127
	LOOKOUT POINT-DEXTER	2051	2059	6	6	.05571	R	6
	MCNARY	2051	2059	67	67	.05571	R	67
	LITTLE GOOSE	2051	2059	45	45	.05571	R	45
	GREEN PETER-FOSTER	2051	2058	19	19	.05554	R	19

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	BONNEVILLE	2051	2056	72,812	72,812	.05488	R	72,812
	TOTAL							156,524
2052	ICE HARBOR	2052	2082	407	407	.05949	R	407
	HILLS CREEK	2052	2082	389	389	.05949	R	389
	COLUMBIA BASIN	2052	2087	44,684	44,684	.05949	R	44,684
	BONNEVILLE	2052	2087	79,089	79,089	.05949	R	79,089
	ICE HARBOR	2052	2097	225	225	.05949	R	225
	MINIDOKA	2052	2097	6,912	6,912	.05949	R	6,912
	HILLS CREEK	2052	2097	629	629	.05949	R	629
	LOST CREEK	2052	2077	84	84	.05864	R	84
	BONNEVILLE	2052	2077	15	15	.05864	R	15
	BOISE	2052	2077	24,348	24,348	.05864	R	24,348
	COLUMBIA BASIN	2052	2067	953	953	.05692	R	953
	MINIDOKA	2052	2067	97	97	.05692	R	97
	ICE HARBOR	2052	2062	14,976	14,976	.05607	R	14,976
	COUGAR	2052	2060	4	4	.05571	R	4
	LOWER GRANITE	2052	2059	27	27	.05554	R	27
	DETROIT-BIG CLIFF	2052	2059	3	3	.05554	R	3
	ICE HARBOR	2052	2057	15,363	15,363	.05488	R	15,363
	TOTAL							188,205
2053	LOWER SNAKE F AND W	2053	2088	1,282	1,282	.05949	R	1,282
	DWORSHAK	2053	2093	8,674	8,674	.05949	R	8,674
	HUNGRY HORSE	2053	2103	52,082	52,082	.05949	R	52,082
	LOWER GRANITE	2053	2078	132	132	.05864	R	132
	LITTLE GOOSE	2053	2078	43	43	.05864	R	43
	HUNGRY HORSE	2053	2078	12,103	12,103	.05864	R	12,103
	COLUMBIA BASIN	2053	2078	55,867	55,867	.05864	R	55,867
	CHIEF JOSEPH	2053	2078	385	385	.05864	R	385
	THE DALLES	2053	2073	254	254	.05778	R	254
	HUNGRY HORSE	2053	2073	795	795	.05778	R	795
	DWORSHAK	2053	2073	3,845	3,845	.05778	R	3,845
	LOWER GRANITE	2053	2068	352	352	.05692	R	352
	COLUMBIA BASIN	2053	2068	1,288	1,288	.05692	R	1,288
	CHIEF JOSEPH	2053	2068	227	227	.05692	R	227
	LOWER MONUMENTAL	2053	2065	2,582	2,582	.05641	R	2,582
	LOWER SNAKE F AND W	2053	2063	1,168	1,168	.05607	R	1,168
	DWORSHAK	2053	2063	207	207	.05607	R	207

YEAR ----------INVESTMENT PAID----------

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	DWORSHAK	2053	2061	43	43	.05571	R	43
	BONNEVILLE	2053	2061	4,519	4,519	.05571	R	4,519
	LOWER SNAKE F AND W	2053	2060	642	642	.05554	R	642
	LOOKOUT POINT-DEXTER	2053	2060	17	17	.05554	R	17
	LOWER MONUMENTAL	2053	2060	26	26	.05554	R	26
	LIBBY	2053	2060	77	77	.05554	R	77
	ICE HARBOR	2053	2060	29,048	29,048	.05554	R	29,048
	MCNARY	2053	2060	32	32	.05554	R	32
	BONNEVILLE	2053	2060	30,984	30,984	.05554	R	30,984
	LOWER SNAKE F AND W	2053	2058	54	54	.05488	R	54
	TOTAL							206,728
2054	LOWER MONUMENTAL	2054	2079	45	45	.05864	R	45
	DETROIT-BIG CLIFF	2054	2079	120	120	.05864	R	120
	DETROIT-BIG CLIFF	2054	2079	234	234	.05864	R	234
	DETROIT-BIG CLIFF	2054	2074	334	334	.05778	R	334
	DETROIT-BIG CLIFF	2054	2074	5,164	5,164	.05778	R	5,164
	COUGAR	2054	2069	49	49	.05692	R	49
	JOHN DAY	2054	2066	49	49	.05641	R	49
	DETROIT-BIG CLIFF	2054	2064	36	36	.05607	R	36
	JOHN DAY	2054	2061	31	31	.05554	R	31
	THE DALLES	2054	2059	49	49	.05488	R	49
	TOTAL							6,111
2055	LIBBY	2055	2090	8,798	8,798	.05949	R	8,798
	LOWER GRANITE	2055	2095	7,947	7,947	.05949	R	7,947
	MCNARY	2055	2105	22,661	22,661	.05949	R	22,661
	MCNARY	2055	2080	1,029	1,029	.05864	R	1,029
	LOOKOUT POINT-DEXTER	2055	2080	39	39	.05864	R	39
	LOOKOUT POINT-DEXTER	2055	2080	605	605	.05864	R	605
	ALBENI FALLS	2055	2080	2,866	2,866	.05864	R	2,866
	LOWER GRANITE	2055	2075	40,279	40,279	.05778	R	40,279
	LOOKOUT POINT-DEXTER	2055	2075	85	85	.05778	R	85
	LOOKOUT POINT-DEXTER	2055	2075	497	497	.05778	R	497
	MCNARY	2055	2075	1,392	1,392	.05778	R	1,392
	ALBENI FALLS	2055	2075	1,052	1,052	.05778	R	1,052
	THE DALLES	2055	2067	10	10	.05641	R	10
	LOWER SNAKE F AND W	2055	2067	586	586	.05641	R	586
	LITTLE GOOSE	2055	2067	2,582	2,582	.05641	R	2,582

YEAR ----INVESTMENT PAID----

(ALL AMOUNT IN $1000)

YEAR	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
	LOWER GRANITE	2055	2065	1,003	1,003	.05607	R	1,003
	LOOKOUT POINT-DEXTER	2055	2065	123	123	.05607	R	123
	MCNARY	2055	2065	65,841	65,841	.05607	R	65,841
	ALBENI FALLS	2055	2065	1	1	.05607	R	1
	THE DALLES	2055	2063	80	80	.05571	R	80
	GREEN PETER-FOSTER	2055	2063	15	15	.05571	R	15
	LOWER GRANITE	2055	2063	36	36	.05571	R	36
	LOWER SNAKE F AND W	2055	2063	123	123	.05571	R	123
	COUGAR	2055	2062	3	3	.05554	R	3
	LITTLE GOOSE	2055	2062	26	26	.05554	R	26
	TOTAL							157,679
2056	LIBBY	2056	2096	17,632	17,632	.05949	R	17,632
	ICE HARBOR	2056	2096	4,879	4,879	.05949	R	4,879
	YAKIMA-CHANDLER	2056	2106	3,723	3,723	.05949	R	3,723
	YAKIMA-CHANDLER	2056	2081	1,062	1,062	.05864	R	1,062
	LIBBY	2056	2076	750	750	.05778	R	750
	YAKIMA-CHANDLER	2056	2076	99	99	.05778	R	99
	ICE HARBOR	2056	2076	219	219	.05778	R	219
	YAKIMA-CHANDLER	2056	2066	67	67	.05607	R	67
	LIBBY	2056	2066	77	77	.05607	R	77
	BONNEVILLE	2056	2061	72,812	72,812	.05488	R	72,812
	TOTAL							101,320
	GRAND TOTAL							12,054,941
	TOTAL DEFERRAL							0
	NET							12,054,941