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

2010 BPA Rate Case
Wholesale Power Rate Initial Proposal

REVENUE REQUIREMENT STUDY

February 2009

WP-10-E-BPA-02

BONNEVILLE POWER ADMINISTRATION

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REVENUE REQUIREMENT STUDY

TABLE OF CONTENTS

Page

TABLES

FIGURE

APPENDICES

COMMONLY USED ACRONYMS

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

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

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

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

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

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1. INTRODUCTION

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

The cost evaluation period, as defined by the Federal Energy Regulatory Commission (FERC), is the period extending from the last year for which historical information is available, through the proposed rate approval period. The cost evaluation period for this rate filing includes Fiscal Year (FY) 2009 as well as the proposed rate approval period (rate test period) of FYs 2010 and 2011. This Study for the rate test period FY 2010-2011 is based on generation revenue requirements that include the results of generation repayment studies. This Study does not include revenue requirements or a cost recovery demonstration for BPA's transmission function.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine revenue requirements. Chapter 5 of this Study summarizes the legal requirements related to revenue requirements and repayment studies. Volumes 1 and 2 of the Revenue Requirement Study Documentation, WP-10-E-BPA-02A and WP-10-E-BPA-02B, respectively, contain key technical assumptions and calculations, the results of the generation repayment studies, and a further explanation of the repayment program and its outputs.

The revenue requirement for this study was 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 extend over the 50-year repayment period. Second, generation operating expenses and minimum required net revenues (MRNR) are projected for each year of the rate test period. Third, annual Planned Net Revenues for Risk (PNRR) are determined after taking into account risks, BPA's cost recovery goals, and other risk mitigation measures, as described in the Risk Analysis and Mitigation Study, WP-10-E-BPA-04. From these three steps, the revenue requirement is set at the revenue level necessary to fulfill cost recovery requirements and objectives through the process depicted in Figure 1, Generation Revenue Requirement Process.

Consistent with Department of Energy (DOE) order RA 6120.2, described in Chapter 5 of this Study, and the standards applied by FERC on review of BPA's rates, the adequacy of both current and proposed rates must be demonstrated. BPA conducts a current revenue test to determine whether revenues projected from current rates meet cost recovery requirements for the rate test period and the repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements are met, current rates could be extended through the proposed rate approval period. The current revenue test, described in section 4.2 of this Study, demonstrates that revenues from current rates will not recover the generation revenue requirement for the rate test period. The revised revenue test determines whether projected revenues from proposed rates meet cost recovery requirements and objectives for the rate test and repayment periods. The revised revenue test, contained in section 4.3 of this Study, demonstrates that revenues from the proposed wholesale power rates recover generation costs in the rate test period as well as over the ensuing 50-year repayment period. Rate test period costs are projected to be recovered with a very high confidence level, meeting BPA's 95 percent probability standard that all U.S. Treasury payments in the generation function will be recovered on time and in full through wholesale power rates for a two-year period. See the Risk Analysis and Mitigation Study, WP-10-E-BPA-04.

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed rates for FY 2010-2011. These net revenues are the lowest level necessary to achieve BPA's cost recovery objectives, when combined with other risk mitigation tools, given hydro condition uncertainty, market price volatility, and other risks.

Table 1: Projected Net Revenues from Projected Rates

($000s)

	A	**B**
	FY 2010	FY 2011
Projected Revenues from Proposed Rates	$2,994,386	$3,132,066
Projected Expenses	2,814,032	3,092,935
Net Revenues	$184,354	$39,131

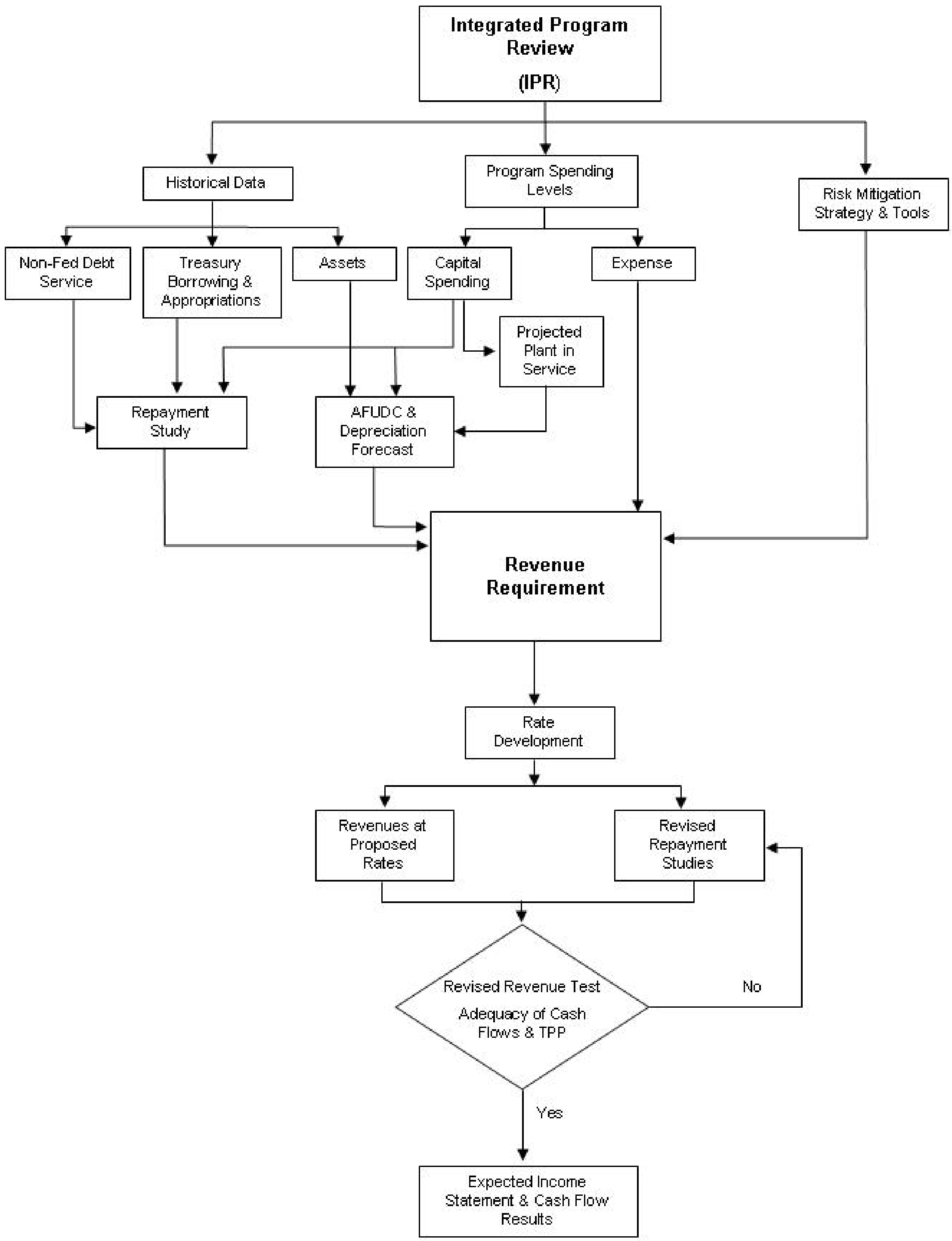
Table 2 shows planned generation amortization payments to the U.S. Treasury during the rate test period and irrigation assistance payments that are due to be paid from power revenues. To partially compensate for an unexpected and unintended cost shift between Slice and other preference customers, it was necessary to shift $50 million in planned amortization from FY 2011 to FY 2010. This was accomplished without changing the total amount planned for the rate period. This reshaping amortization has been a longstanding practice in BPA rate proposals.

See, for example, WP-07 Revenue Requirement Study, WP-07-FS-BPA-02. The rescheduled amortization and its attendant changes to interest expense have been applied to the development of the base revenue requirement income statement (Table 5A) and statement of cash flows (Table 5B).

Table 2: Planned Federal Amortization & Irrigation Assistance Payments
($000s)

	A	**B**
Annual Fiscal Year	Amortization	Irrigation Assistance
2010	$267,264	$0
2011	$161,888	$0
Total	$429,152	$0

Figure 1: Revenue Requirement Process



2. SPENDING LEVEL DEVELOPMENT

2.1 Development Process for WP-10 Initial Proposal Spending Levels

The development of specific program spending levels reflected in this Initial Proposal occurred primarily in the Integrated Program Review (IPR), a sub-process of the Integrated Business Review (IBR). The Integrated Business Review process was designed in response to the interest expressed by participants in the Regional Dialogue process in having a long-term cost control process that allows customers meaningful input.

2.1.1 Regional Dialogue

The Regional Dialogue process evolved out of an effort sponsored jointly by BPA and the Northwest Power and Conservation Council (NPCC) to outline how BPA should market the power generated by the FCRPS. The first phase addressed issues needing immediate resolution for the post-2006 rate period and culminated in the Policy for Power Supply Role for Fiscal Years 2007-2011 and record of decision (ROD) (Near-Term Policy and ROD), issued in February 2005. The second phase addressed post-FY 2011 power service issues and culminated in the Long-Term Regional Dialogue Final Policy and ROD issued in July 2007.

In the Long-Term Policy BPA committed to establish a regional cost review and cost control process that would, among other things, address agency capital and expense levels in one forum and examine major anticipated financial policy decisions that could affect rates. The process would put an emphasis on rate period costs prior to rate cases and ensure regular access to clear and transparent financial information and frequent opportunities for meaningful input into BPA cost and program decisions during rate periods as well. After BPA conducted a public comment period and held focus groups to obtain customer and constituent input on the structure of the regional cost review process, BPA designed the IBR.

2.1.2 Integrated Business Review

Although the Long-Term Policy and ROD focus on post-FY 2011 issues, BPA chose to implement the cost review process, now known as the IBR, as soon as practicable. The IBR was first used in support of the WP-07 Supplemental rate case. It entails two processes, the IPR and the Quarterly Business Review (QBR). The IPR was designed to create a centralized forum for addressing and reviewing power and transmission proposed program spending levels prior to inclusion in a rate case. The QBR is an ongoing forum designed to update and inform customers and constituents of the current financials, cost trends, and emerging issues that could affect rates in the future.

BPA will revisit the IBR process at least every five years to review whether it is meeting the needs of BPA and its stakeholders.

2.1.3 Integrated Program Review

The IPR was designed to provide customers and constituents with an opportunity to examine, understand, and comment on BPA's cost projections for both power and transmission rate proposals. BPA began the IPR for FY 2010-2011 program levels on May 15, 2008, with an opening workshop containing an overview of all Power Services and Transmission Services proposed spending levels through FY 2011. After completion of the opening workshop, a total of eight days of technical workshops and one managerial level workshop were held through July 30, 2008, on FY 2010-2011 Power Services program levels. These workshops were held to discuss the projected spending levels and capital programs of the Columbia Generating Station (CGS), U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (Reclamation), conservation program, renewables program, fish and wildlife program, Power Services internal operations, transmission purchases and ancillary services program, and BPA corporate costs.

While Federal and non-Federal debt management issues are not decided in the IPR, workshops were held on these topics because BPA believes it is important for participants to understand the implications of past debt management decisions and proposed capital spending levels.

Comments gathered in these forums included an early request by participants for additional information about possible alternative program levels. On July 29, BPA released a "draft report." The draft report did not propose different spending levels for the FY 2010-2011 period, although it did provide two illustrative scenarios for each program, one that explored the impacts of a 10-percent increase and one that explored the impacts of a 10-percent decrease in proposed program spending levels. This material was also presented and discussed at the July 30 workshop.

The public comment period ran from May 15, 2008, to August 15, 2008. Based on comments received during the IPR process, BPA changed some forecasted program spending levels for the WP-10 Initial Proposal. These changes included an $18 million reduction to Conservation capital in FY 2010 and a $10 million reduction to Conservation capital in FY 2011. The renewable rate credit, originally proposed to be zero in the initial IPR, has been increased to $4 million in FY 2010 and $2.5 million in FY 2011. Many of the forecasts in the initial IPR were not modified. However, BPA committed to an additional, abbreviated IPR process outside of this rate proceeding during the spring of 2009 to review spending forecasts for FY 2010-2011, considering any new information available at that time, and to update forecasts if necessary. The result of that process will be reflected in the Final Proposal.

The IPR FY 2010-2011 Power and Transmission Program Levels Final Report, included in Appendix A of this Study, describes in greater detail the outcomes of the IPR process.

2.2 Capital Funding

The forecast of FCRPS capital investments for FY 2010-2011 was updated in the IPR for the WP-10 Initial Proposal. The following section reflects forecasts developed in the IPR with inclusion of a 15 percent "lapse factor," recognizing that timing of planned capital spending may be stretched into the following rate period. The lapse factor was applied to all programs except the Fish and Wildlife Program and CGS. FCRPS capital investments include COE, Reclamation, and BPA capital investments as well as third-party resource investments for which debt is secured by BPA (capitalized contracts). Projections of current FCRPS capital outlays are $1,254 million for the cost evaluation period. These investments include:

- improvements and maintenance needed to increase reliability, safety, and performance at the Columbia Generating Station nuclear plant (CGS);
- improvements and maintenance needed to improve reliability of the aging and deteriorating Federal hydro system;
- increase in the renewable rate credit to reflect the expectation that utilities are likely to need additional assistance in acquiring and using renewable resource power to serve their retail loads;
- investment in conservation activities; and
- investment in capital equipment.

Table 4, which follows this section, provides a detailed breakout of investment projections for the cost evaluation period, FY 2009 through 2011. This Study projects that no capital investments will be funded from current revenues.

2.2.1 Bonds Issued to the U.S. Treasury

Bonds issued to the U.S. Treasury are the source of capital that will be used to finance FY 2010-2011 BPA capital program investments and COE and Reclamation investments that

BPA has agreed to direct-fund under Section 2406 of P.L. No. 102-486, 16 U.S.C. § 839d-1. These expenditures include a projection of $558.9 million split among BPA Fish and Wildlife direct program investments ($328.7 million), conservation investments ($71.4 million), BPA capital equipment ($28.8 million), and generating resource investments of the COE and Reclamation ($328.7 million) during FY 2010-2011.

Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to interest rates on securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in Chapter 6 of Volume 1 of the Documentation, WP-10-E-BPA-02A.

2.2.2 Federal Appropriations

The revenue requirement study, in general, reflects that all COE and Reclamation capital investments in the FCRPS will be financed by Federal appropriations unless they are direct-funded by BPA. This Study includes projected appropriated investments totaling $184 million during the rate period for COE fish and wildlife mitigation and recovery measures through the Columbia River Fish Mitigation (CRFM) project. No other appropriations-financed investments are forecast for the rate period. Capital investments funded by this source do not become BPA's obligation until placed in service.

The interest rate forecast for appropriated capital investments expected to be placed in service is found in Chapter 6 of Volume 1 of the Documentation, WP-10-E-BPA-02A. Each new capital investment is assigned a rate from the U.S. Treasury yield curve prevailing in the month prior to the beginning of the fiscal year in which the new investment is placed in service.

To determine interest during construction for new capital investments, the prevailing U.S. Treasury one-year rate for each fiscal year of construction is applied to the sum of the cumulative expenditures made and interest during construction that has accrued prior to the end of the subject fiscal year. *See* Study Chapter 5 and Documentation, WP-10-E-BPA-02A, Chapter 9.

2.2.3 Third-Party Debt

Third-party debt differs from U.S. Treasury debt in that entities other than BPA or U.S. Treasury issue the debt. BPA's promise to make payments serves as security for bonds or other debt that the third party issues, resulting in wider market access and potentially more favorable interest rates for the seller. Examples of acquisitions financed in this way include the Energy Northwest, Inc. (EN) WNP-1, WNP-3, and CGS nuclear power projects, and the Lewis County Public Utility District Hydroelectric project (Cowlitz Falls). This Study includes debt service on $146.6 million in total projected CGS capital investments by EN to be financed by issuing bonds in FY 2010 and 2011. Each new projected capital investment is assigned an interest rate from the tax exempt municipal bond yield curve corresponding with the term of the bond, as shown in Chapter 6 of Volume 1 of the Documentation, WP-10-E-BPA-02A.

2.3 Debt Optimization Program

After base power rates were filed for the FY 2002-2006 rate period, BPA instituted a Debt Optimization Program (DOP) with EN as a means of replenishing Treasury borrowing authority. Debt Optimization (DO) involves extending EN debt that has come due and using the cash flows that would have gone to pay the EN debt to repay an equivalent amount of Federal debt. The program has resulted in a considerable amount of Federal debt, primarily bonds issued to Treasury but also some Congressional appropriations, being paid well in advance of the amortization schedules established in the WP-02 rate filing. As the program continued during the FY 2007-2009 rate period, this created additional advance amortization, compared to the schedules that would have been established without DO, for the subsequent rate periods through FY 2012. Effectively, the extension of EN debt into the FY 2013-2018 period has advanced the repayment of Federal debt relative to the amount that otherwise would have been scheduled to be paid in that period. BPA has committed to EN that it would follow this program, matching dollar-for-dollar the repayment of Federal obligations in the same year in which EN debt has been extended, absent dire financial circumstances that might cause some delay in the payment of the advanced portion of the amortization.

Although DO actions may occur during the cost evaluation period, only EN debt refinancing transactions completed through FY 2008 are incorporated in the development of this rate proposal. However, in establishing amortization schedules for FY 2010-2011, EN bonds that were refinanced in FY 2001-2002 more than 90 days in advance of their due dates, known as advanced refundings, are taken into account in preparing repayment studies in order to fulfill the commitment for the dollar-for-dollar repayment of Federal obligations. The total planned annual amortization was derived through a two-phase repayment study procedure. A base level of amortization was established for each year of the rate period as though EN advanced refundings had not occurred. The additional amortization equivalent to the EN principal advance refinanced in each year was then added to the base schedule. Table 3 shows the composition of the resulting planned annual amortization payments.

Table 3: Composition of Annual Amortization Payments
($000s)

	A	B	C
Fiscal Year	Base Amortization	Advanced Amortization	Total Amortization
2010	$176,670	$ 38,500	$215,170
2011	$150,342	$ 70,000	$220,342
Total	$327,012	$108,500	$435,512

Table 4: FCRPS Projected Capital Funding Requirements

	($ in millions)	A 2009	B 2010	C 2011
	Capital Requirements for Revenue Producing Investments			
1	Corps & Bureau Additions/Replacements - Direct Funded	133.2	157.9	170.9
2	Corps & Bureau Additions/Replacements - Appropriations [1]	-	-	-
3	PBL Capital Equipment	16.5	13.9	15.0
4	CGS: Additions/Replacements [2]	27.7	92.0	54.6
5	Other Non - Federal	-	-	-
6	**Annual Capital Requirements for Revenue Producing Investments**	177.4	263.7	240.4
7	**Cumulative Capital Requirements for Rev Producing Investments**	177.4	441.2	681.6
	Capital Requirements for Non-Revenue Producing and Public Benefit Investments			
8	**Energy Conservation**	27.2	32.3	39.1
9	**Fish Investment**			
10	BPA Fish and Wildlife Investment	50.0	70.0	60.0
11	Corps & Bureau Fish Investment - Appropriations	110.0	88.0	96.0
12	**Total Fish Investment**	160.0	158.0	156.0
13	Other Third - Party	-	-	-
14	**Annual Capital Req. for Non-Rev. & Public Benefit Invests.**	187.2	190.3	195.1
15	**Cumulative Capital Req. for Non-Rev. & Public Benefit Invest.**	187.2	377.5	572.6
16	**ANNUAL FUNDING REQUIREMENTS FOR POWER**	364.6	454.0	435.5
17	**CUMULATIVE FUNDING REQUIREMENTS FOR POWER FOR THE RATE PERIOD**	364.6	818.7	1,254.2

FOOTNOTES:

[1] Reflects plant in service, including IDC, not expenditures.

[2] CGS new capital requirements were revenue-financed prior to FY 2002.
FY 2009 includes bond amounts for capital to be issued for Energy Northwest FY 2010.

3. DEVELOPMENT OF REVENUE REQUIREMENTS

Typically, repayment studies are performed as the first step in determining revenue requirements. The studies establish a schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments. Each repayment study covers a rate test year and the ensuing repayment period, which extends to the last year by which all outstanding and projected obligations must be repaid. For power repayment studies that is 50 years.

In conducting the repayment studies, BPA includes as fixed inputs the annual debt service payments associated with its capitalized contract obligations and the fixed annual payments associated with long-term energy resource acquisition contracts. All outstanding and projected generation repayment obligations for appropriated investments (including irrigation assistance) and bonds issued to the U.S. Treasury are included to be scheduled for repayment. Funding for replacements projected during the repayment period are also included in the repayment study, consistent with the requirements of RA 6120.2.

Appropriations are scheduled to be repaid within the expected useful life of the associated facility or 50 years, whichever is less. COE and Reclamation project 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.

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

In addition, the interest rate that BPA pays on callable bonds is higher than the interest rate on non-callable bonds issued at the same time.

Bonds are issued to finance BPA conservation acquisition, the Fish and Wildlife Program, and COE and Reclamation investments direct-funded by BPA, and are repaid within the terms and conditions of each bond issued to the U.S. Treasury. Bonds to finance fish and wildlife capital investments are issued with maturities not to exceed 15 years, the same period over which BPA amortizes these capital investments. COE and Reclamation direct-funding bonds are issued with maturities not to exceed 45 years. Conservation bonds are issued with maturities that are consistent with the period over which BPA amortizes these capital investments. Currently, BPA has three amortization schedules for conservation assets. Investments made prior to FY 2002, referred to as the Conservation Legacy program, have a straight-line, 20-year amortization period. Investments made from FY 2002 through FY 2006, known as Conservation Augmentation investments, have a declining 10-year amortization period to be completed by 2011. Investments made beginning in FY 2007, known as Conservation Acquisition investments, will have a straight-line five-year amortization period. *See* Administrator's Record of Decision, WP-07-A-02, section 4.4.

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 this Study, WP-10-E-BPA-02, and in Chapter 9 of Volume 2 of the Documentation, WP-10-E-BPA-02B. Chapter 5 of this Study provides explanation of repayment policies and requirements.

4. GENERATION REVENUE REQUIREMENT

4.1 Revenue Requirement Format

For each year of a rate test period, BPA prepares two tables that constitute the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, PNRR, and if necessary, an MRNR component. The Statement of Cash Flows shows the analysis used to determine MRNR and the cash available for risk mitigation.

The Income Statement (Table 5A) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 20), Net Interest Expense (Line 29), and Total Planned Net Revenues (Line 33), which consist of MRNR (Line 31), and PNRR (Line 32). The sum of these three major components is the Total Revenue Requirement (Line 34).

The amounts shown in Total Operating Expenses and Net Interest Expense are primarily established outside the ratesetting process in the IPR. The MRNR (Line 31) results from an analysis of the Statement of Cash-Flow (Table 5B). MRNR 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 irrigation assistance payments.

The Statement of Cash-Flow analyzes annual cash inflows and outflows. Cash provided by Current Operations (Line 8), driven by the Non-Cash items shown in Lines 4, 5, 6, and 7, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 14) and Cash from Treasury Borrowing and Appropriations (Line 21). If cash provided by Current Operations is not sufficient, MRNR must be included in revenue requirements to accommodate the shortfall, yielding at least zero annual Increase in Cash (Line 22). The MRNR amounts shown on the Statement of Cash Flows (Line 2) are then incorporated in the Income Statement (Line 27).

4.1.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 5A). Volume 1 of the Documentation, WP-10-E-BPA-02A, provides additional information on the development and use of the data contained in the tables.

Power System Generation Resources (Line 2). This category encompasses the costs associated with power generated by Federal hydroelectric facilities operated by the COE and Reclamation and power obtained through contracts for non-Federal resources and through energy conservation. This category includes lines 3 through 11, described below.

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

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

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

Contracted Power Purchases (Line 6). This category includes short-term (balancing) power purchases and hedging/mitigation.

Augmentation Power Purchases (Line 7). This category includes augmentation power purchases, the DSI monetized power sale, and the PNCA headwater benefit. Augmentation power purchase costs reflect the energy that BPA purchases in order to satisfy its obligation to meet the load requirements for public utilities. The PNCA headwater benefit refers to the costs associated with benefits BPA receives from storage projects in Canada.

Exchanges and Settlements (Line 8). This category represents the net benefits for qualifying public utilities and IOUs that are calculated as part of the Residential Exchange Program as well as the cost for operating the program.

Renewable Generation (Line 9). This category reflects the operating expenses of several generating projects fueled by renewable energy resources such as wind, geothermal, methane gas, solar, and "fish-friendly small hydro projects."

Generation Conservation (Line 10). This category includes the cost of conservation programs including Marketing Development, which are reimbursable contracts with equal and offsetting revenues, Market Transformation, Legacy Conservation programs, Technology Leadership, and Low-Income Weatherization.

Conservation and Renewable Discount (Line 11). This category includes credits paid to qualifying BPA customers that have taken action to achieve cost-effective conservation and renewable resource development in the region.

Transmission Acquisition and Ancillary Services (Line 12). This category includes the annual expenses associated with Power Services' Transmission Acquisition program. It represents costs associated with services necessary to deliver energy from resources to markets and loads. This includes transmission, ancillary services, and real power losses, as purchased from BPA's Transmission Services business unit (TS) or non-Federal entities; TS embedded costs for the facilities that integrate power from COE and Reclamation projects onto the transmission system; and metering and communication requirements.

Power Non-Generation Operations (Line 13). This category reflects Power Services' internal costs associated with supporting the power function. It includes the costs of activities such as generation oversight, weather and streamflow forecasting, system operations planning, schedule planning, pre-scheduling, after-the-fact accounting of power transactions, power billing, customer account executives and customer service support staff, development and administration of power sales contracts, PS strategy development, PS financial reporting, analysis and budgeting, risk management, and PS human resources management.

F&W/Environmental Requirements (Line 14). BPA funds projects designed to protect, mitigate and enhance fish and wildlife affected by the FCRPS in a manner consistent with the NPCC Columbia River Basin Fish and Wildlife Program, and to implement commitments made pursuant to Biological Opinions (BiOps) issued by NOAA Fisheries and the U.S. Fish and Wildlife Service regarding species listed under the Endangered Species Act. 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 fish and wildlife mitigation consistent with the NPCC Fish and Wildlife Program as well BiOps issued by the NOAA Fisheries (also known as the National Marine Fisheries Service (NMFS)) for listed salmon and steelhead and the U.S. Fish and Wildlife Service (USFWS) for listed bull trout and sturgeon.

General and Administrative/Shared Services (Line 15). This category represents the allocated portion of BPA's Corporate General and Administrative costs, which are allocated to the business lines. Major functions besides the Executive Office are Corporate Communication, Finance, Diversity, and Safety. This category also includes Shared Services and the Civil Service Retirement System (CSRS) expense. Shared Services represents the costs for information technology services, infrastructure and maintenance, building rent, maintenance and security, mail services, personnel services, library and printing services, internal training, purchasing, and furniture. CSRS reflects the costs for the unfunded liability of the Civil Service Retirement and Disability Fund, the Employees Health Benefit Fund, and the Employees Life Insurance Fund.

Other Income, Expenses, and Adjustments (Line 16). This category consists of the annual cost of the Flexible PF Rate Program.

Non-Federal Debt Service (Line 17). This category consists of third-party debt service or payment costs associated with capitalized contracts and other long-term, fixed contractual obligations. Debt service costs associated with EN projects (WNP-1, CGS, and WNP-3) make up the majority of these costs. Documentation, WP-10-E-BPA-02A, Chapter 9.

Depreciation (Line 18). 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 (LSRCP)) plant, including assets for fish and wildlife recovery, is depreciated by the straight-line method of calculation, using the composite service life of all projects, 75 years. Capital equipment (office furniture and fixtures, data processing hardware and software, and communications equipment) is also depreciated by the straight-line method using the average service lives for the particular categories of capital investment. *Id.*, Chapters 3 and 4.

Amortization (Line 19). Amortization is the annual capital recovery expense associated with non-revenue-producing assets. Conservation investments are amortized over three different periods, as described in Chapter 3. Legacy conservation investments prior to the FY 2002-2006 rate period are amortized using a straight-line, 20-year life. Conservation Augmentation investments in the FY 2002-2006 period are amortized using a declining life method, with all amortization being complete in FY 2011. Conservation Acquisition investments beginning in FY 2007 are amortized using a straight-line, five-year life. *Id.*

Total Operating Expenses (Line 20). Total Operating Expenses is the sum of the above expenses (Lines 2 through 15).

Interest on Appropriated Funds (Line 23). Interest on Appropriated Funds includes interest on COE and Reclamation appropriations, as calculated in the generation repayment studies. *Id.*, Chapters 4 and 6.

Capitalization Adjustment (Line 24). 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.

Interest on Bonds Issued to U.S. Treasury (Line 25). Interest on long-term debt includes interest on bonds that BPA issues to the U.S. Treasury to fund investments in capital equipment, conservation, and fish and wildlife, and to fund Reclamation and COE investments under the Energy Policy Act of 1992 (EPA-92) (P.L. No. 102-486, 1992 U.S. Code Cong. & Admin. News, 106 Stat. 2776). The interest expense is calculated in the generation repayment studies. Any payments of call premiums for bonds projected to be amortized are included in this line. Documentation, WP-10-E-BPA-02A, Chapters 4 and 6.

Amortization of Capitalized Bond Premiums (Line 26). When a bond issued to the U.S. Treasury is refinanced, any call premium resulting from early retirement of the original bond is capitalized and included in the principal of the new bond. The capitalized call premium is then amortized over the term of the new bond. The annual amortization is a non-cash component of interest expense.

Allowance for Funds Used During Construction (AFUDC) (Line 27). AFUDC is a credit against interest costs on long-term debt (Line 20). This reduction to gross interest 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 and BPA capital equipment.

Interest Credit (Line 28). An interest income credit is also computed on the projected year-end cash balance in the BPA fund attributable to Power Services that carries over into the next year. Also included is an interest income credit calculated in the generation repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year. Interest income is credited against bond interest. *Id.*, at Chapter 6.

Net Interest Expense (Line 29). Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 23), Capitalization Adjustment (Line 24), Interest on Bonds Issued to U.S. Treasury (Line 25), Amortization of Capitalized Bond Premiums (Line 26), AFUDC (Line 27), and Interest Credit (Line 28).

Total Expenses (Line 30). Total Expenses are the sum of Total Operating Expenses (Line 20) and Net Interest Expense (Line 29).

Minimum Required Net Revenues (Line 31). MRNR, 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 MRNR is included in section 4.1.2.

Planned Net Revenues for Risk (PNRR) (Line 32). PNRR are the amount of net revenues to be included in rates for financial risk mitigation. PNRR, starting reserves, the cash-flow when non-cash expenses exceed cash payments, the CRAC, and other risk mitigation tools are available to mitigate risk in FY 2007-2009, as discussed in the Risk Analysis and Mitigation Study, WP-10-E-BPA-04.

Total Planned Net Revenues (Line 33). Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 27) and PNRR (Line 28).

Total Revenue Requirement (Line 30). Total Revenue Requirement is the sum of Total Expenses (Line 31) and Total Planned Net Revenues (Line 32).

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 the Documentation, WP-10-E-BPA-02A and WP-10-E-BPA-02B, provide additional information related to the use and development of the data contained in the table.

Minimum Required Net Revenues (Line 2). Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. MRNR may be necessary so that the cash provided from operating activities will be sufficient to cover the planned amortization and irrigation assistance payments (the difference between Lines 8 and 21) without causing the Annual Increase (Decrease) in Cash (Line 22) to be negative. The MRNR amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 31).

Depreciation and Amortization (Line 4). Depreciation and Amortization are from the Income Statement (Table 5A), lines 18 and 19 respectively. They are included in computing

Cash Provided By Operating Activities (Line 8) because they are non-cash expenses of the FCRPS.

Amortization of Capitalized Bond Premiums (Line 5). Amortization of capitalized bond premiums is from the Income Statement (Table 5A, line 26). It is included in computing Cash Provided By Operating Activities (Line 8) because it is a non-cash expense of the FCRPS.

Capitalization Adjustment (Line 6). Capitalization Adjustment is from the Income Statement (Table 5A, Line 24). It is a non-cash contra-expense.

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

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

Investment in Federal Utility Plant (Including AFUDC) (Line 11). Investment in Utility Plant represents the annual increase in additions to appropriated plant-in-service and to capital expenditures for COE, Reclamation, and BPA construction work-in-progress funded by bonds. Documentation, WP-10-E-BPA-02A, Chapter 4.

Investment in Conservation (Line 12). Investment in Conservation represents the annual increase in capital expenditures associated with Conservation programs. *Id.*

Investment in Fish and Wildlife (Line 13). Investment in Fish and Wildlife represents the annual increase in BPA's capital expenditures to fund projects for the protection, mitigation and enhancement of fish and wildlife affected by the FCRPS in a manner consistent with the NPCC's Columbia River Basin Fish and Wildlife Program and the BiOp issued by NMFS and USFWS.

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

Increase in Treasury Debt (Line 16). This category reflects the new bonds issued by BPA to the U.S. Treasury to fund capital equipment, conservation, and fish and wildlife capital programs and to direct-fund Reclamation and COE investments under the EPA-92. *Id.*, Chapter 7.

Repayment of Treasury Debt (Line 17). This is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury as determined in the generation repayment studies. *Id.*, Chapter 6.

Increase in Federal Construction Appropriations (Line 18). Increase in Congressional Capital Appropriations represents Congressional appropriations projected to be received during the year for COE and Reclamation capital projects. *Id.*, Chapter 4.

Repayment of Federal Construction Appropriations (Line 19). Repayment of Capital Appropriations represents projected amortization of outstanding COE and Reclamation appropriations as determined in the generation repayment studies. *Id.*, Chapter 6.

Payment of Irrigation Assistance (Line 20). Payment of Irrigation Assistance represents the payment of appropriated capital construction costs of Reclamation irrigation facilities that have been determined to be beyond the ability of the irrigators to pay and allocated to generation revenues for repayment. *Id.*, Chapter 9.

Cash Provided by Borrowing and Appropriations (Line 21). Cash Provided by Borrowing and Appropriations is the sum of Lines 16 through 20. This is the net cash-flow resulting from increases in cash from new long-term debt and capital appropriations and decreases in cash from repayment of long-term debt and capital appropriations.

Annual Increase (Decrease) in Cash (Line 22). Annual Increase (Decrease) in Cash is the sum of Lines 8, 14, and 21 and reflects the annual net cash-flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash-flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues would be insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease.

Planned Net Revenues for Risk (PNRR) (Line 23). PNRR reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives from Table 5A, Line 32.

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

4.2 Current Revenue Test

Consistent with RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test, Tables 6 and 7, determines whether the revenues expected from current rates can continue to meet cost recovery requirements, thus allowing the current rates to be extended. Revenues at current rates can be found in the documentation of the Wholesale Power Rate Development Study (WPRDS), WP-10-E-BPA-05A, section 5. The results of the current revenue test demonstrate that current rates are inadequate to ensure cost recovery.

4.3 Revised Revenue Test

Consistent with RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements as well as BPA's Treasury Payment Probability (TPP) standard for the rate period. The revised revenue test was conducted using the base case forecast of revenues under proposed rates. WPRDS Documentation, WP-10-E-BPA-05A, Section 5. The test also included changes in expenses, such as Residential Exchange Benefits, which is an outcome of the rate development process. *See* Figure 1.

BPA revised its estimate of the cost of the Residential Exchange Program to an annual average $254.4 million because it is an outcome of the rate development process. Table 5A, which serves as the starting point for the rate development process, included only the operations cost of the program of approximately $2 million per year. This change was incorporated in the revised revenue test, as it is the most current spending level forecast for that program.

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 28) for making the planned annual amortization and irrigation assistance payments and achieving the Administrator's financial objectives. This is demonstrated by the Annual Increase (Decrease) in Cash (Line 22). The annual cash-flow (Line 22) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash requirements. The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery requirements and meet risk mitigation policy for the rate period of FY 2010-2011.

4.4 Repayment Test at Proposed Rates

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

The historical data on this table have been taken from BPA's separate accounting analysis. The rate test period data have been developed specifically for this rate filing. The repayment period data are presented consistent with the requirements of RA 6120.2. Typically, the revenue test through the repayment period uses expenses from the last year of the rate period. In this case, expenses for the CGS nuclear plant were normalized because it is on a two-year refueling cycle, which results in low costs in the first year and high costs in the second year. FY 2011 is a refueling year for CGS, which increases O&M costs for the facility and power purchase costs to make up for the loss of generation during the refueling. The CGS outage in FY 2011 will be unusually long due to a planned condenser tube replacement project, which will lengthen the time CGS is out of service. The projection of these costs through the repayment period would misrepresent the costs associated with the CGS refueling cycle. For the purposes of this revenue test, these costs have been normalized by averaging FY 2011 CGS costs with FY 2010 CGS costs to produce an average cost for the operation of CGS and for augmentation purchases to make up for lost CGS generation.

5. REVENUE REQUIREMENT LEGAL REQUIREMENTS AND POLICIES

This chapter summarizes the following policies:

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

5.1 Development of BPA's Revenue Requirements

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

5.1.1 Legal Requirements Governing the FCRPS Revenue Requirement

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

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

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

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

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

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

> Columbia River Transmission System Act (16 U.S.C. § 838), Section 5 of the Flood Control Act of 1944, and the provisions of this of this [Act].

Section 7(n) of the Northwest Power Act provides additional guidance regarding cost recovery for the FY 2010-2011 rate period, and preserves BPA's ability to establish appropriate reserves subsequent to FY 2006:

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

16 U.S.C. § 839e(n).

The Northwest Power Act also makes it clear that a primary purpose of confirmation of BPA rates by FERC is to ensure that the revenue requirement is adequate to ensure 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 BPA supplementary authority to sell bonds to the U.S. Treasury to finance BPA's new conservation and renewable resource programs. *See* 16 U.S.C. § 838i. EPA-92 clarified BPA's authority to provide funds directly to 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 this Study.

5.1.2 Colville Settlement Act Credits

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

The Settlement Agreement obligates BPA to make annual payments to the Colville Tribes. Payments have been tied to both BPA's average prices and the amount of annual generation from Grand Coulee Dam. Under the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-13, 110 Stat. 1321, BPA receives annual credits from the U.S. Treasury against payments due the U.S. Treasury in order to defray a portion of the costs of making payments to the Colville Tribes. Revenues credited to BPA associated with the Settlement Agreement are $21.3 million in FY 2010 and $21.7 million in FY 2011. The credits for the FY 2010-2011 rate period are forecast to be $4.6 million in each fiscal year.

5.1.3 The BPA Appropriations Refinancing Act

As in the prior rate period, BPA's power rates for the FY 2010-2011 rate period will reflect the requirements of the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, 16 U.S.C. § 838l, P.L. No. 104-134, 110 Stat. 1321, enacted in April 1996. The Refinancing Act required that unpaid principal on FCRPS appropriations (old capital investments) at the end of FY 1996 be reset at the present value of the principal and annual interest payments BPA would make to the U.S. Treasury for these obligations absent the Refinancing Act, plus $100 million. *Id*. at §838l(b)(I). The Refinancing Act also specifies that the new principal amounts of the old capital investments be assigned new interest rates from the U.S. Treasury yield curve prevailing at the time of the refinancing transaction. *Id*. at § 838l(a)(6)(A).

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

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

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

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

16 U.S.C. § 838l(a)(6)(B).

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

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

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

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

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

Id.

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

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

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

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

The Northwest Power Act provides that:

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

16 U.S.C. § 839b(h)(10)(A).

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

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

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 25-year history of conducting separate repayment studies for the transmission and generation functions, which has enabled BPA to transition to a bifurcated rate setting process with minimal change in repayment policy and development of the revenue requirement. Consistent with the decision to conduct bifurcated hearings for the transmission and generation functions beginning with the WP-02 proceeding, the Revenue Requirement Study incorporates only the separate repayment study for the generation function of the FCRPS for FY 2010-2011.

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 the U.S. Treasury. The details of the repayment policy have largely been established through administrative interpretation of statutory requirements, with Congressional sanction.

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

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

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

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

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

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

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

On March 22, 1976, the DOI issued Chapter 4 of Part 730 of the DOI Manual to codify financial reporting requirements for the DOI 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 40 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 five years, and for fish and wildlife facilities to be 15 years];
- the Federally -financed amount of each replacement within its service life up to a maximum of 50 years; and

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

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

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.

ADDITIONAL TABLES

Table 5A: Generation Revenue Requirement Income Statement

($000s)

		A 2010	B 2011
1	OPERATING EXPENSES		
2	POWER SYSTEM GENERATION RESOURCES		
3	OPERATING GENERATION	581,789	693,804
4	OPERATING GENERATION SETTLEMENT PAYMENT	21,328	21,754
5	NON-OPERATING GENERATION	2,618	2,728
6	CONTRACTED POWER PURCHASES	71,235	57,155
7	AUGMENTATION POWER PURCHASES	176,305	304,610
8	EXCHANGES & SETTLEMENTS	2,421	1,440
9	RENEWABLE GENERATION	45,588	45,938
10	GENERATION CONSERVATION	55,088	54,722
11	CONSERVATION AND RENEWABLE DISCOUNT	32,000	32,000
12	PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	173,162	170,570
13	POWER NON-GENERATION OPERATIONS	82,793	86,650
14	F&W/USF&W/PLANNING COUNCIL/ENVIRONMENTAL REQUIREMENTS	263,541	270,618
15	GENERAL AND ADMINISTRATIVE/SHARED SERVICES	67,475	68,341
16	OTHER INCOME, EXPENSES AND ADJUSTMENTS	1,800	3,600
17	NON-FEDERAL DEBT SERVICE	556,052	576,365
18	DEPRECIATION	118,616	119,921
19	AMORTIZATION	79,118	86,989
20	TOTAL OPERATING EXPENSES	2,330,928	2,597,205
21	INTEREST EXPENSE:		
22	INTEREST		
23	APPROPRIATED FUNDS	222,131	208,672
24	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
25	BONDS ISSUED TO U.S. TREASURY	49,849	68,317
26	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
27	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(10,800)	(10,200)
28	INTEREST CREDIT	(49,605)	(49,317)
29	NET INTEREST EXPENSE	165,823	171,720
30	TOTAL EXPENSES	2,496,751	2,768,925
31	MINIMUM REQUIRED NET REVENUES 1/	118,806	4,254
32	PLANNED NET REVENUES FOR RISK	48,000	48,000
33	PLANNED NET REVENUES, TOTAL (31+32)	166,806	52,254
34	TOTAL REVENUE REQUIREMENT	2,663,557	2,821,179

1/ SEE NOTE ON CASH FLOW STATEMENT

Table 5B: Generation Revenue Requirement Statement of Cash Flows

($000s)

		A 2010	B 2011
1	CASH PROVIDED BY OPERATING ACTIVITIES		
2	MINIMUM REQUIRED NET REVENUES 1/	118,806	4,254
3	NON-CASH ITEMS:		
4	DEPRECIATION AND AMORTIZATION	197,734	206,910
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
7	ACCRUAL REVENUES	(3,524)	(3,524)
8	CASH PROVIDED BY OPERATING ACTIVITIES	267,264	161,888
9	CASH USED FOR INVESTMENT ACTIVITIES:		
10	INVESTMENT IN:		
11	FEDERAL UTILITY PLANT (INCLUDING AFUDC)	(259,721)	(281,800)
12	CONSERVATION	(32,300)	(39,100)
13	FISH & WILDLIFE	(70,000)	(60,000)
14	CASH USED FOR INVESTMENT ACTIVITIESS	(362,021)	(380,900)
15	CASH FROM AND (USED FOR) FINANCING ACTIVITIES		
16	INCREASE IN TREASURY DEBT	274,021	284,900
17	REPAYMENT OF TREASURY DEBT	(68)	0
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	88,000	96,000
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(267,196)	(161,888)
20	PAYMENT OF IRRIGATION ASSISTANCE	0	0
21	CASH USED FOR FINANCING ACTIVITIES	94,757	219,012
22	ANNUAL INCREASE (DECREASE) IN CASH	0	0
23	PLANNED NET REVENUES FOR RISK	48,000	48,000
24	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	48,000	48,000

1/ Line 22 must be greater than or equal to zero to indicate that cash cost recovery requirements are being achieved. If they are not, net revenues (MRNR) are added so that net cash flows for the year, prior to any cash considerations for risk mitigation, are zero.

Table 6A: Generation Current Revenue Test Income Statement

($000s)

		A 2010	B 2011
1	REVENUES FROM PROPOSED RATES	2,784,447	2,884,560
2	OPERATING EXPENSES		
3	POWER SYSTEM GENERATION RESOURCES		
4	OPERATING GENERATION	581,789	693,804
5	OPERATING GENERATION SETTLEMENT PAYMENT	21,328	21,754
6	NON-OPERATING GENERATION	2,618	2,728
7	CONTRACTED POWER PURCHASES	124,004	113,000
8	AUGMENTATION POWER PURCHASES	176,580	304,818
9	EXCHANGES & SETTLEMENTS	255,259	277,486
10	RENEWABLE GENERATION	45,588	45,938
11	GENERATION CONSERVATION	55,088	54,722
12	CONSERVATION AND RENEWABLE DISCOUNT	32,000	32,000
13	PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	173,162	170,570
14	POWER NON-GENERATION OPERATIONS	82,793	86,650
15	F&W/USF&W/PLANNING COUNCIL/ENVIRONMENTAL REQUIREMENTS	263,541	270,618
16	GENERAL AND ADMINISTRATIVE/SHARED SERVICES	67,475	68,341
17	OTHER INCOME, EXPENSES AND ADJUSTMENTS	1,800	3,600
18	NON-FEDERAL DEBT SERVICE	556,052	576,365
19	DEPRECIATION	118,616	119,921
20	AMORTIZATION	79,118	86,989
21	TOTAL OPERATING EXPENSES	2,636,810	2,929,303
22	INTEREST EXPENSE:		
23	INTEREST		
24	APPROPRIATED FUNDS	222,131	208,672
25	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
26	BONDS ISSUED TO U.S. TREASURY	49,849	68,317
27	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
28	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(10,800)	(10,200)
29	INTEREST CREDIT	(44,089)	(30,665)
30	NET INTEREST EXPENSE	171,339	190,372
31	TOTAL EXPENSES	2,808,149	3,119,675
32	NET REVENUES	(23,702)	(235,115)

Table 6B: Generation Current Revenue Test Statement of Cash Flows

($000s)

		A 2010	B 2011
1	CASH PROVIDED BY OPERATING ACTIVITIES		
2	NET REVENUES	(23,702)	(235,115)
3	NON-CASH ITEMS:		
4	DEPRECIATION AND AMORTIZATION	197,734	206,910
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
7	ACCRUAL REVENUES	(3,524)	(3,524)
8	CASH PROVIDED BY OPERATING ACTIVITIES	124,755	(77,482)
9	CASH USED FOR INVESTMENT ACTIVITIES:		
10	INVESTMENT IN:		
11	FEDERAL UTILITY PLANT (INCLUDING AFUDC)	(259,721)	(281,800)
12	CONSERVATION	(32,300)	(39,100)
13	FISH & WILDLIFE	(70,000)	(60,000)
14	CASH USED FOR INVESTMENT ACTIVITIESS	(362,021)	(380,900)
15	CASH FROM AND (USED FOR) FINANCING ACTIVITIES		
16	INCREASE IN TREASURY DEBT	274,021	284,900
17	REPAYMENT OF TREASURY DEBT	(68)	0
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	88,000	96,000
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(267,196)	(161,888)
20	PAYMENT OF IRRIGATION ASSISTANCE	0	0
21	CASH USED FOR FINANCING ACTIVITIES	94,757	219,012
22	ANNUAL INCREASE (DECREASE) IN CASH	(142,509)	(239,370)

Table 7: Generation Revenues from Current Rates – Results Through the Repayment Period

($000s)

	A	B	C	D	E	F	G	H	I	J	K
YEAR COMBINED CUMULATIVE	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION 2/ (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
GENERATION											
1978	217,534	40,331	51,130	36,511	81,883	7,679	46,521	54,200	6,937		47,263
1979	189,542	49,347	25,195	39,083	98,889	(22,972)	42,586	19,614	914		18,700
1980	341,863	76,460	182,743	41,237	105,740	(64,317)	94,441	30,124	73		30,051
1981	502,589	92,990	269,625	42,870	118,861	(21,757)	48,941	27,184	4,410 3/		22,774
1982	1,067,604	115,430	945,442	49,355	145,610	(188,233)	55,427	(132,806)	0		(132,806)
1983	1,485,741	114,960	1,255,810	57,967	153,763	(96,759)	64,039	(32,720)	0		(32,720)
1984	2,248,654	146,870	1,898,859	67,644	170,942	(35,661)	257,382	221,721	192,294 4/		29,427
1985	2,371,829	137,664	1,898,178	75,711	173,888	86,388	75,711	162,099	37,354		124,745
1986	2,179,326	135,632	1,895,153	84,162	175,257	(110,878)	84,162	(26,716)	10,587		(37,303)
1987	2,014,040	154,184	1,826,711	91,552	199,448	(257,855)	91,552	(166,303)	2,471		(168,774)
1988	2,303,479	183,326	1,796,029	98,288	204,416	21,420	98,288	119,708	149,778		(30,070)
1989	2,273,508	173,694	1,760,205	100,104	189,446	50,059	100,104	150,163	32,875		117,288
1990	2,315,035	198,721	1,527,829	105,338	197,462	285,685	105,338	391,023	63,336		327,687
1991	2,482,482	216,777	1,572,046	103,047	167,559	423,053	103,047	526,100	114,583		411,517
1992	2,142,645	287,360	1,821,930	110,403	169,711	(246,759)	110,403	(136,356)	57,543		(193,899)
1993	2,233,989	309,915	1,868,863	118,143	186,455	(249,387)	118,143	(131,244)	117,974		(249,218)
1994	2,536,059	316,352	1,934,944	125,396	197,222	(37,855)	125,396	87,541	135,018		(47,477)
1995	2,704,285	327,420	1,915,529	141,798	215,850	103,688	141,798	245,486	196,544		48,942
1996	2,744,510	366,808	1,959,406	151,122	208,509	58,665	154,024	197,689 5/	135,010		62,679
1997	1,996,439	612,961	924,789	148,215	197,238	113,236	105,956	219,192	82,971	25,143	111,078
1998	2,060,750	665,005	1,091,678	162,562	201,930	(60,425)	118,892	76,812	61,000		15,812
1999	2,366,423	702,717	1,196,308	162,008	182,079	123,311	118,951	311,083	25,000		286,083
2000	2,720,940	723,377	1,410,029	165,874	169,320	252,340	119,184	366,345	175,338		191,007
2001	3,888,051	819,270	2,945,886	168,433	166,504	(212,042)	121,506	(143,592)	151,062	16,560	(311,214)
2002	3,047,803	833,606	1,925,873	174,164	201,582	(87,422)	127,491	(3,414)	369,800		(373,214)
2003	3,144,811	705,289	1,841,035	178,896	176,595	242,996	131,592	314,144	73,000		241,144
2004	2,738,898	713,549	1,366,265	177,298	162,531	319,255	129,789	354,413	233,000	739	120,674
2005	2,814,224	711,713	1,420,735	186,099	166,610	329,067	(98,072)	320,734	271,301		49,433
2006	2,853,659	875,605	1,516,332	181,878	157,609	122,235	(84,357)	355,358	261,276		94,082
2007	2,657,891	695,564	1,484,767	176,204	145,516	155,840	133,875	289,715	246,300		43,415
2008	2,383,688	802,849	1,224,722	183,466	142,746	29,905	138,142	195,087	277,483	2,950	(85,346)
COST EVALUATION PERIOD											
2009	2,664,037	912,984	1,305,232	188,579	132,750	124,492	142,827	263,795	191,065	7,274	65,456
RATE APPROVAL PERIOD											
2010	2,784,447	977,886	1,461,190	197,734	171,339	(23,702)	151,982	124,756	267,264		(142,508)
2011	2,884,560	1,004,716	1,717,677	206,910	190,372	(235,115)	161,158	(77,481)	161,888		(239,369)
REPAYMENT PERIOD											
2012	2,884,560	1,004,716	1,684,754	206,910	212,425	(224,244)	161,158	(66,610)	97,537	1,206	(165,353)
2013	2,884,560	1,004,716	1,628,165	206,910	217,632	(172,863)	161,158	(15,229)	90,097	60,027	(165,353)
2014	2,884,560	1,004,716	1,621,683	206,910	219,085	(167,834)	161,158	(10,200)	86,142	69,011	(165,353)
2015	2,884,560	1,004,716	1,590,724	206,910	221,613	(139,402)	161,158	18,232	32,300	151,285	(165,353)
2016	2,884,560	1,004,716	1,725,890	206,910	230,375	(283,331)	161,158	(125,697)	39,100	554	(165,351)

Table 7 cont.

REPAYMENT PERIOD	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C PURCHASE AND EXCHANGE POWER (STATEMENT E)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION 2/ (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	J IRRIGATION AMORTIZATION (STATEMENT C)	K NET POSITION (K=H-I-J)
2017	2,884,560	1,004,716	1,759,736	206,910	236,179	(322,982)	161,158	(165,348)	0	1	(165,349)
2018	2,884,560	1,004,716	1,591,597	206,910	239,438	(158,101)	161,158	(467)	136,897	27,989	(165,353)
2019	2,884,560	1,004,716	1,103,511	206,910	225,373	344,050	161,158	501,684	608,869	58,168	(165,353)
2020	2,884,560	1,004,716	1,203,933	206,910	192,207	276,794	161,158	434,428	574,838	24,943	(165,353)
2021	2,884,560	1,004,716	1,203,942	206,910	159,023	309,969	161,158	467,603	620,602	12,354	(165,353)
2022	2,884,560	1,004,716	1,203,933	206,910	122,414	346,587	161,158	504,221	654,989	14,585	(165,353)
2023	2,884,560	1,004,716	1,204,343	206,910	87,569	381,022	161,158	538,656	690,757	13,252	(165,353)
2024	2,884,560	1,004,716	1,245,472	206,910	61,326	366,137	161,158	523,771	673,710	15,414	(165,353)
2025	2,884,560	1,004,716	1,354,938	206,910	13,679	304,318	161,158	461,952	613,405	13,900	(165,353)
2026	2,884,560	1,004,716	1,354,714	206,910	(15,518)	333,737	161,158	491,371	635,570	21,154	(165,353)
2027	2,884,560	1,004,716	1,354,872	206,910	(46,006)	364,068	161,158	521,702	426,353	192,572	(97,222)
2028	2,884,560	1,004,716	1,355,040	206,910	(62,177)	380,071	161,158	537,705	55,898	21,250	460,557
2029	2,884,560	1,004,716	1,355,220	206,910	(62,173)	379,887	161,158	537,521	50,186	196,308	291,027
2030	2,884,560	1,004,716	1,355,412	206,910	(62,168)	379,690	161,158	537,324	45,188	0	492,136
2031	2,884,560	1,004,716	1,355,617	206,910	(62,163)	379,480	161,158	537,114	70,741	0	466,373
2032	2,884,560	1,004,716	1,355,837	206,910	(63,897)	380,995	161,158	538,629	36,816	0	501,813
2033	2,884,560	1,004,716	1,356,071	206,910	(63,892)	380,755	161,158	538,389	72,599	0	465,790
2034	2,884,560	1,004,716	1,356,321	206,910	(65,201)	381,814	161,158	539,448	53,078	0	486,370
2035	2,884,560	1,004,716	1,356,588	206,910	(65,195)	381,541	161,158	539,175	53,600	0	485,575
2036	2,884,560	1,004,716	1,356,875	206,910	(65,188)	381,248	161,158	538,882	63,788	0	475,094
2037	2,884,560	1,004,716	1,357,179	206,910	(65,766)	381,520	161,158	539,154	54,656	0	484,498
2038	2,884,560	1,004,716	1,357,506	206,910	(65,758)	381,186	161,158	538,820	55,244	0	483,576
2039	2,884,560	1,004,716	1,357,855	206,910	(65,750)	380,829	161,158	538,463	100,872	0	437,591
2040	2,884,560	1,004,716	1,358,227	206,910	(68,254)	382,961	161,158	540,595	56,480	0	484,115
2041	2,884,560	1,004,716	1,358,625	206,910	(68,245)	382,554	161,158	540,188	87,125	0	453,063
2042	2,884,560	1,004,716	1,359,050	206,910	(70,311)	384,195	161,158	541,829	162,806	0	379,023
2043	2,884,560	1,004,716	1,359,505	206,910	(77,553)	390,983	161,158	548,617	104,460	0	444,157
2044	2,884,560	1,004,716	1,359,990	206,910	(80,561)	393,505	161,158	551,139	136,311	0	414,828
2045	2,884,560	1,004,716	1,360,509	206,910	(86,158)	398,584	161,158	556,218	73,402	0	510,544
2046	2,884,560	1,004,716	1,361,063	206,910	(87,845)	399,716	161,158	557,350	45,674	0	514,232
2047	2,884,560	1,004,716	1,361,656	206,910	(87,831)	399,109	161,158	556,743	43,118	0	513,625
2048	2,884,560	1,004,716	1,362,289	206,910	(87,816)	398,461	161,158	556,095	40,728	0	515,367
2049	2,884,560	1,004,716	1,362,965	206,910	(87,800)	397,769	161,158	555,403	36,747	0	518,656
2050	2,884,560	1,004,716	1,363,688	206,910	(87,783)	397,029	161,158	554,663	33,205	0	521,458
2051	2,884,560	1,004,716	1,364,460	206,910	(87,765)	396,239	161,158	553,873	30,083	0	523,790
2052	2,884,560	1,004,716	1,365,284	206,910	(87,745)	395,395	161,158	553,029	27,321	0	525,708
2053	2,884,560	1,004,716	1,366,165	206,910	(87,724)	394,493	161,158	552,127	42,785	0	509,342
2054	2,884,560	1,004,716	1,367,108	206,910	(87,702)	393,529	161,158	551,163	43,358	0	507,805
2055	2,884,560	1,004,716	1,368,114	206,910	(87,678)	392,498	161,158	550,132	43,962	0	506,170
2056	2,884,560	1,004,716	1,369,189	206,910	(87,653)	391,398	161,158	549,032	44,597	0	504,435
2057	2,884,560	1,004,716	1,370,338	206,910	(87,626)	390,222	161,158	547,856	45,216	0	502,640
2058	2,884,560	1,004,716	1,371,565	206,910	(87,597)	388,965	161,158	546,599	45,864	0	500,735
2059	2,884,560	1,004,716	1,372,878	206,910	(87,566)	387,622	161,158	545,256	46,542	0	498,714
2060	2,884,560	1,004,716	1,284,892	206,910	(89,647)	477,689	161,158	635,323	47,245	0	588,078
2061	2,884,560	1,004,716	1,017,834	206,910	(95,962)	751,062	161,158	908,696	0	0	908,696
GENERATION TOTALS	205,166,535	60,413,552	111,513,758	13,609,001	5,916,692	13,713,533	10,688,329	24,482,342	10,418,806	946,640	11,714,543

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

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

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

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

1 5/REDUCED BY $15,000 OF REVENUE FINANCING.

Table 8A: Generation Revised Revenue Test Income Statement

($000s)

		A	B
		2010	**2011**
1	REVENUES FROM PROPOSED RATES	2,994,386	3,132,066
2	OPERATING EXPENSES		
3	POWER SYSTEM GENERATION RESOURCES		
4	OPERATING GENERATION	581,789	693,804
5	OPERATING GENERATION SETTLEMENT PAYMENT	21,328	21,754
6	NON-OPERATING GENERATION	2,618	2,728
7	CONTRACTED POWER PURCHASES	124,004	113,000
8	AUGMENTATION POWER PURCHASES	176,580	304,818
9	EXCHANGES & SETTLEMENTS	265,857	266,293
10	RENEWABLE GENERATION	45,588	45,938
11	GENERATION CONSERVATION	55,088	54,722
12	CONSERVATION AND RENEWABLE DISCOUNT	32,000	32,000
13	PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	173,162	170,570
14	POWER NON-GENERATION OPERATIONS	82,793	86,650
15	F&W/USF&W/PLANNING COUNCIL/ENVIRONMENTAL REQUIREMENTS	263,541	270,618
16	GENERAL AND ADMINISTRATIVE/SHARED SERVICES	67,475	68,341
17	OTHER INCOME, EXPENSES AND ADJUSTMENTS	1,800	3,600
18	NON-FEDERAL DEBT SERVICE	556,052	576,365
19	DEPRECIATION	118,616	119,921
20	AMORTIZATION	79,118	86,989
21	TOTAL OPERATING EXPENSES	2,647,408	2,918,110
22	INTEREST EXPENSE:		
23	INTEREST		
24	APPROPRIATED FUNDS	222,131	208,672
25	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
26	BONDS ISSUED TO U.S. TREASURY	49,849	68,317
27	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
28	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(10,800)	(10,200)
29	INTEREST CREDIT	(48,804)	(46,212)
30	NET INTEREST EXPENSE	166,624	174,825
31	TOTAL EXPENSES	2,814,032	3,092,935
32	NET REVENUES	180,354	39,131

Table 8B: Generation Revised Revenue Test Statement of Cash Flows

($000s)

		A 2010	B 2011
1	CASH PROVIDED BY OPERATING ACTIVITIES		
2	NET REVENUES	180,354	39,131
3	NON-CASH ITEMS:		
4	DEPRECIATION AND AMORTIZATION	197,734	206,910
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
6	CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
7	ACCRUAL REVENUES	(3,524)	(3,524)
8	CASH PROVIDED BY OPERATING ACTIVITIES	328,811	196,764
9	CASH USED FOR INVESTMENT ACTIVITIES:		
10	INVESTMENT IN:		
11	FEDERAL UTILITY PLANT (INCLUDING AFUDC)	(259,721)	(281,800)
12	CONSERVATION	(32,300)	(39,100)
13	FISH & WILDLIFE	(70,000)	(60,000)
14	CASH USED FOR INVESTMENT ACTIVITIESS	(362,021)	(380,900)
15	CASH FROM AND (USED FOR) FINANCING ACTIVITIES		
16	INCREASE IN TREASURY DEBT	274,021	284,900
17	REPAYMENT OF TREASURY DEBT	(68)	0
18	INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	88,000	96,000
19	REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(267,196)	(161,888)
20	PAYMENT OF IRRIGATION ASSISTANCE	0	0
21	CASH USED FOR FINANCING ACTIVITIES	94,757	219,012
22	ANNUAL INCREASE (DECREASE) IN CASH	61,547	34,876

Table 9: Generation Revenues from Proposed Rates – Results Through the Repayment Period

($000s)

	A	B	C	D	E	F	G	H	I	J	K
YEAR COMBINED CUMULATIVE	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION 2/ (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
GENERATION											
1978	217,534	40,331	51,130	36,511	81,883	7,679	46,521	54,200	6,937		47,263
1979	189,542	49,347	25,195	39,083	98,889	(22,972)	42,586	19,614	914		18,700
1980	341,863	76,460	182,743	41,237	105,740	(64,317)	94,441	30,124	73		30,051
1981	502,589	92,990	269,625	42,870	118,861	(21,757)	48,941	27,184	4,410 3/		22,774
1982	1,067,604	115,430	945,442	49,355	145,610	(188,233)	55,427	(132,806)	0		(132,806)
1983	1,485,741	114,960	1,255,810	57,967	153,763	(96,759)	64,039	(32,720)	0		(32,720)
1984	2,248,654	146,870	1,898,859	67,644	170,942	(35,661)	257,382	221,721	192,294 4/		29,427
1985	2,371,829	137,664	1,898,178	75,711	173,888	86,388	75,711	162,099	37,354		124,745
1986	2,179,326	135,632	1,895,153	84,162	175,257	(110,878)	84,162	(26,716)	10,587		(37,303)
1987	2,014,040	154,184	1,826,711	91,552	199,448	(257,855)	91,552	(166,303)	2,471		(168,774)
1988	2,303,479	183,326	1,796,029	98,288	204,416	21,420	98,288	119,708	149,778		(30,070)
1989	2,273,508	173,694	1,760,205	100,104	189,446	50,059	100,104	150,163	32,875		117,288
1990	2,315,035	198,721	1,527,829	105,338	197,462	285,685	105,338	391,023	63,336		327,687
1991	2,482,482	216,777	1,572,046	103,047	167,559	423,053	103,047	526,100	114,583		411,517
1992	2,142,645	287,360	1,821,930	110,403	169,711	(246,759)	110,403	(136,356)	57,543		(193,899)
1993	2,233,989	309,915	1,868,863	118,143	186,455	(249,387)	118,143	(131,244)	117,974		(249,218)
1994	2,536,059	316,352	1,934,944	125,396	197,222	(37,855)	125,396	87,541	135,018		(47,477)
1995	2,704,285	327,420	1,915,529	141,798	215,850	103,688	141,798	245,486	196,544		48,942
1996	2,744,510	366,808	1,959,406	151,122	208,509	58,665	154,024	197,689 5/	135,010		62,679
1997	1,996,439	612,961	924,789	148,215	197,238	113,236	105,956	219,192	82,971	25,143	111,078
1998	2,060,750	665,005	1,091,678	162,562	201,930	(60,425)	118,892	76,812	61,000		15,812
1999	2,366,423	702,717	1,196,308	162,008	182,079	123,311	118,951	311,083	25,000		286,083
2000	2,720,940	723,377	1,410,029	165,874	169,320	252,340	119,184	366,345	175,338		191,007
2001	3,888,051	819,270	2,945,886	168,433	166,504	(212,042)	121,506	(143,592)	151,062	16,560	(311,214)
2002	3,047,803	833,606	1,925,873	174,164	201,582	(87,422)	127,491	(3,414)	373,345		(376,759)
2003	3,144,811	705,289	1,841,035	178,896	176,595	242,996	131,592	314,144	73,000		241,144
2004	2,738,898	713,549	1,366,265	177,298	162,531	319,255	129,789	354,413	233,000	739	120,674
2005	2,814,224	711,713	1,420,735	186,099	166,610	329,067	(98,072)	320,734	271,301		49,433
2006	2,853,659	875,605	1,516,332	181,878	157,609	122,235	(84,357)	355,358	261,276		94,082
2007	2,657,891	695,564	1,484,767	176,204	145,516	155,840	133,875	289,715	246,300		43,415
2008	2,383,688	802,849	1,224,722	183,466	142,746	29,905	138,142	195,087	277,483	2,950	(85,346)
COST EVALUATION PERIOD											
2009	2,664,037	912,984	1,305,232	188,579	132,750	124,492	142,827	263,795	191,065	7,274	65,456
RATE APPROVAL PERIOD											
2010	2,994,386	977,886	1,471,789	197,734	166,624	180,353	151,982	328,811	267,264		61,547
2011	3,132,066	1,004,716	1,706,485	206,910	174,825	39,130	161,158	196,764	161,888		34,876
REPAYMENT PERIOD											
2012	3,132,066	1,004,716	1,684,754	206,910	192,641	43,046	161,158	200,680	97,537	1,206	101,937
2013	3,132,066	1,004,716	1,628,165	206,910	197,848	94,427	161,158	252,061	90,097	60,027	101,937
2014	3,132,066	1,004,716	1,621,683	206,910	199,301	99,456	161,158	257,090	86,142	69,011	101,937
2015	3,132,066	1,004,716	1,590,724	206,910	201,829	127,888	161,158	285,522	32,300	151,285	101,937
2016	3,132,066	1,004,716	1,725,890	206,910	210,591	(16,041)	161,158	141,593	39,100	554	101,939

Table 9 cont.

	A	B	C	D	E	F	G	H	I	J	K
	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION 2/ (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
2017	3,132,066	1,004,716	1,759,736	206,910	216,395	(55,692)	161,158	101,942	0	1	101,941
2018	3,132,066	1,004,716	1,591,597	206,910	219,654	109,189	161,158	266,823	136,897	27,989	101,937
2019	3,132,066	1,004,716	1,103,511	206,910	205,589	611,340	161,158	768,974	608,869	58,168	101,937
2020	3,132,066	1,004,716	1,203,933	206,910	172,423	544,084	161,158	701,718	574,838	24,943	101,937
2021	3,132,066	1,004,716	1,203,942	206,910	139,239	577,259	161,158	734,893	620,602	12,354	101,937
2022	3,132,066	1,004,716	1,203,933	206,910	102,630	613,877	161,158	771,511	654,989	14,585	101,937
2023	3,132,066	1,004,716	1,204,343	206,910	67,785	648,312	161,158	805,946	690,757	13,252	101,937
2024	3,132,066	1,004,716	1,245,472	206,910	41,542	633,427	161,158	791,061	673,710	15,414	101,937
2025	3,132,066	1,004,716	1,354,938	206,910	(6,105)	571,608	161,158	729,242	613,405	13,900	101,937
2026	3,132,066	1,004,716	1,354,714	206,910	(35,302)	601,027	161,158	758,661	635,570	21,154	101,937
2027	3,132,066	1,004,716	1,354,872	206,910	(65,790)	631,358	161,158	788,992	426,353	192,572	170,068
2028	3,132,066	1,004,716	1,355,040	206,910	(81,961)	647,361	161,158	804,995	55,898	21,250	727,847
2029	3,132,066	1,004,716	1,355,220	206,910	(81,957)	647,177	161,158	804,811	50,186	196,308	558,317
2030	3,132,066	1,004,716	1,355,412	206,910	(81,952)	646,980	161,158	804,614	45,188	0	759,426
2031	3,132,066	1,004,716	1,355,617	206,910	(81,947)	646,770	161,158	804,404	70,741	0	733,663
2032	3,132,066	1,004,716	1,355,837	206,910	(83,681)	648,285	161,158	805,919	36,816	0	769,103
2033	3,132,066	1,004,716	1,356,071	206,910	(83,676)	648,045	161,158	805,679	72,599	0	733,080
2034	3,132,066	1,004,716	1,356,321	206,910	(84,985)	649,104	161,158	806,738	53,078	0	753,660
2035	3,132,066	1,004,716	1,356,588	206,910	(84,979)	648,831	161,158	806,465	53,600	0	752,865
2036	3,132,066	1,004,716	1,356,875	206,910	(84,972)	648,538	161,158	806,172	63,788	0	742,384
2037	3,132,066	1,004,716	1,357,179	206,910	(85,550)	648,810	161,158	806,444	54,656	0	751,788
2038	3,132,066	1,004,716	1,357,506	206,910	(85,542)	648,476	161,158	806,110	55,244	0	750,866
2039	3,132,066	1,004,716	1,357,855	206,910	(85,534)	648,119	161,158	805,753	100,872	0	704,881
2040	3,132,066	1,004,716	1,358,227	206,910	(88,038)	650,251	161,158	807,885	56,480	0	751,405
2041	3,132,066	1,004,716	1,358,625	206,910	(88,029)	649,844	161,158	807,478	87,125	0	720,353
2042	3,132,066	1,004,716	1,359,050	206,910	(90,095)	651,485	161,158	809,119	162,806	0	646,313
2043	3,132,066	1,004,716	1,359,505	206,910	(97,337)	658,273	161,158	815,907	104,460	0	711,447
2044	3,132,066	1,004,716	1,359,990	206,910	(100,345)	660,795	161,158	818,429	136,311	0	682,118
2045	3,132,066	1,004,716	1,360,509	206,910	(105,942)	665,874	161,158	823,508	73,402	0	777,834
2046	3,132,066	1,004,716	1,361,063	206,910	(107,629)	667,006	161,158	824,640	45,674	0	781,522
2047	3,132,066	1,004,716	1,361,656	206,910	(107,615)	666,399	161,158	824,033	43,118	0	780,915
2048	3,132,066	1,004,716	1,362,289	206,910	(107,600)	665,751	161,158	823,385	40,728	0	782,657
2049	3,132,066	1,004,716	1,362,965	206,910	(107,584)	665,059	161,158	822,693	36,747	0	785,946
2050	3,132,066	1,004,716	1,363,688	206,910	(107,567)	664,319	161,158	821,953	33,205	0	788,748
2051	3,132,066	1,004,716	1,364,460	206,910	(107,549)	663,529	161,158	821,163	30,083	0	791,080
2052	3,132,066	1,004,716	1,365,284	206,910	(107,529)	662,685	161,158	820,319	27,321	0	792,998
2053	3,132,066	1,004,716	1,366,165	206,910	(107,508)	661,783	161,158	819,417	42,785	0	776,632
2054	3,132,066	1,004,716	1,367,108	206,910	(107,486)	660,819	161,158	818,453	43,358	0	775,095
2055	3,132,066	1,004,716	1,368,114	206,910	(107,462)	659,788	161,158	817,422	43,962	0	773,460
2056	3,132,066	1,004,716	1,369,189	206,910	(107,437)	658,688	161,158	816,322	44,597	0	771,725
2057	3,132,066	1,004,716	1,370,338	206,910	(107,410)	657,512	161,158	815,146	45,216	0	769,930
2058	3,132,066	1,004,716	1,371,565	206,910	(107,381)	656,255	161,158	813,889	45,864	0	768,025
2059	3,132,066	1,004,716	1,372,878	206,910	(107,350)	654,912	161,158	812,546	46,542	0	766,004
2060	3,132,066	1,004,716	1,284,892	206,910	(109,431)	744,979	161,158	902,613	47,245	0	855,368
2061	3,132,066	1,004,716	1,017,834	206,910	(115,746)	1,018,352	161,158	1,175,986	0	0	1,175,986
GENERATION TOTALS	216,761,750	60,413,552	111,513,165	13,609,001	5,006,150	26,219,883	10,688,329	36,988,692	10,422,351	946,640	24,217,348

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

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

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

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

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

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APPENDIX A

INTEGRATED PROGRAM REVIEW

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Department of Energy

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

FINANCE

November 14, 2008

In reply refer to: F-2

To Our Customers, Constituents, Tribes and Other Stakeholders:

The Bonneville Power Administration (BPA) now brings to a close the Integrated Program Review (IPR) examination of FY 2010-2011 Power and Transmission costs that began on May 15, 2008.

Between the opening "Overview" workshop and the end of June, eight days of technical workshops were held covering all Power and Transmission program levels through FY 2011. The Administrator hosted a management-level meeting on July 2, 2008, to hear comments personally, and a public comment period was held from May 15 through August 15, 2008. Through this process, BPA sought to provide interested parties with meaningful opportunities to examine, understand, and provide input on the cost projections that would be included in the initial proposals for FY 2010-2011 Power and Transmission rates. These initial proposals are expected to be published in February 2009. In addition, FY 2009 Power program levels were reviewed and commented on, and a final report on those cost projections was provided on July 23, 2008. BPA appreciates the participation and input you provided during this process, especially given the numerous other concurrent and important processes. We have found it beneficial.

BPA believes the program levels reflected in the attached report are an appropriate balance between minimizing impacts to ratepayers in the short term and the need to make investments for the long term. In particular, BPA identified the following areas that need investment now: the transmission system; the aging and deteriorating Federal hydro system; the reliability, safety and performance of Columbia Generating Station; environmental and regulatory obligations and safety and security needs; and the internal infrastructure necessary to support the business.

BPA identified roughly $8 million in net reductions for FY 2009 Power costs compared to draft IPR levels. For FY 2010-2011, BPA determined it is appropriate to restore the renewable rate credit, increasing costs by $2.5 million and $4 million for those years. Reductions in capital forecasts have also been made through this IPR process. These changes are detailed in the attached report. Cost forecasts for BPA's Power and Transmission rate proposals must be finalized now to allow the rate process to stay on schedule. BPA will use the attached report for this purpose.

Customers challenged us to find additional cost reductions in several areas. We do not believe it is prudent to include additional cost reductions in rates unless and until we are confident we can deliver them. We will continue to examine costs over the next several months. We believe that progress on several fronts, including the Network Open Season, Regional Dialogue, Biological Opinion, renewable and conservation activities, and asset plans over that time will make the potential for additional savings more clear. Also, the implications for BPA and the region of recent events in global financial markets and indications of a severe economic downturn need to be evaluated. Prior to submitting final rate proposals in July 2009, BPA will assess any new or updated information available and determine if we believe further cost changes are appropriate. We will conduct an abbreviated public review of these costs in the March/April time frame, with the results being incorporated into the final rate proposals. BPA accomplishes review of proposed spending levels outside its formal rate case to allow for substantial public input, and the decisions are not revisited in the rate case.

Thank you very much for your attention and input to the IPR for FY 2010-2011 Power and Transmission costs. For further information on the IPR or other issues, please contact your Customer Account Executive, Constituent Account Executive, Tribal Account Executive, or me at (503) 230-5111. The final IPR report and additional information on the process is available at www.bpa.gov/corporate/Finance/IBR/IPR/

Sincerely,

/s/ David J. Armstrong November 14, 2008

David J. Armstrong
Executive Vice President and Chief Financial Officer

Enclosure
IPR FY 2010-2011 Power and Transmission Program Levels Final Report

Bonneville Power Administration
Integrated Program Review
FY 2010-2011 Power and Transmission Program Levels

Final Report
November 14, 2008

BONNEVILLE
POWER ADMINISTRATION

Section 1

Background
and
Summary of Decisions

Integrated Program Review Final Report for FY 2010-2011 Power and Transmission Program Levels

Background

BPA began its first "Integrated Program Review" (IPR) process in May 2008 in response to customer and stakeholder requests for a consolidated program-level review of BPA's planned expenses. This process replaced prior public involvement efforts, including the Capital Program Review, Power Function Review and Transmission's Programs in Review. The IPR is part of the broader Integrated Business Review (IBR). The IBR is structured to give all of BPA's stakeholders a meaningful opportunity to understand and have input to the decisions that drive BPA's costs and the amount of costs going into rate decisions. The IPR process is designed to allow persons interested in BPA's program levels an opportunity to review and comment on all of BPA's expense and capital spending level estimates in the same forum prior to their use in setting rates. BPA intends to hold an IPR every two years, just prior to each rate case.

This initial IPR focused on FY 2010 and 2011 program levels for BPA's Power and Transmission Services as well as a review of proposed Power Services FY 2009 program levels. Decisions on FY 2009 Power Services costs were announced in a separate document released July 18, 2008. Seventeen public workshops were held throughout the IPR, proposed spending levels were presented for each of BPA's programs and active discussion was encouraged by participants. All workshop materials, responses to questions asked during workshops, and additional information requested were posted at www.bpa.gov/corporate/Finance/IBR/IPR/. A managerial level meeting was held on June 30 at which BPA received comments on FY 2010-2011 costs for both Power and Transmission programs.

Early comments included requests by participants for additional information about possible alternative program levels. Specifically, they wanted to understand what would be provided with the proposed increases in BPA spending. They were also interested in understanding the impacts on proposed programs and activities if spending levels were reduced. On July 29, BPA released a "draft report." While this draft report did not propose different spending levels for the FY 2010-2011 period, it did provide two illustrative scenarios for each program, one that explored the impacts of a 10-percent increase and one that explored the impacts of a 10-percent decrease in proposed program level spending. This material was also presented and discussed at the July 30 workshop.

The comment period for the FY 2010-2011 program levels closed August 15. This report addresses the comments received and outlines BPA's decisions regarding the FY 2010-2011 program level forecasts. These forecasts will form the basis for Power and Transmission rate case initial proposals for FY 2010-2011 rates.

Many of the forecasts in the initial IPR were not modified as a result of comments received but will be re-evaluated in an additional public process prior to the development of final rate proposals in the spring of 2009.

Summary of Decisions

BPA carefully reviewed and considered the 18 written comments and numerous oral comments on FY 2010-2011 program levels that were made during this public process. This report summarizes the comments and outlines BPA's responses.

BPA received some comments that recommended specific program level decreases or increases; however, the majority of the comments received were general in nature. For example, suggestions were made that BPA lower program levels, that the impact of program level increases on rate payers be considered, and that BPA consider whether the proposed aggressive capital plan is achievable and necessary. BPA understands the concern over potential near-term rate impacts and joins customers and constituents in the desire to minimize the impact to rates. However, as discussed in the IPR workshops, the proposed program levels reflect a number of new requirements and other factors that are exerting pressure on our costs. BPA believes that not addressing these requirements will jeopardize its ability to provide reliable power services, as well as place other key obligations at considerable risk.

The major drivers of increased Power Services costs are related to:

- Improvements and maintenance needed to increase reliability, safety and performance at the Columbia Generating Station nuclear plant (CGS).
- Improvements and maintenance needed to improve reliability in the aging and deteriorating Federal hydro system.
- New reliability standards.
- New biological opinion requirements and the implementation of Memoranda of Agreement (MOAs) with participating tribes.
- The internal costs recovered in power rates (including costs in both Power Services and Agency Services organizations) in 2008 are roughly the same as they were in 2001, seven years ago. Both inflationary pressures and the other drivers listed here require some increases in these costs.

The major drivers of increased Transmission Services costs are related to:

- New mandatory requirements (reliability, environmental, tariff, etc.).
- Integration of new wind resources into the BPA transmission system.
- Increased demand for transmission capacity.
- Need to sustain the aging Federal transmission assets.
- Need to reinvest in historically underinvested areas, such as control house buildings, access roads, etc.
- Global competition for material.
- As with Power, the internal costs both within Transmission and in Agency Services that support Transmission Services are increasing in response to the drivers shown here and the growing Transmission infrastructure.

Drivers of Agency Services costs are largely the same as those for Power and Transmission. The cost increases in many of the Agency Services activities (such as Information Technology, General Counsel, Finance, Supply Chain, and Human Capital Management) are due to the need for increased support of Power and Transmission activities. Agency Services activities are integral to both continuing activities and the achievement of enhanced programmatic goals. In addition to its more traditional General and Administration activities, Agency Services also includes the centralized Technology Innovation and Confirmation (Research and Development) program. In keeping with a long-term plan outlined in the IPR and previous public involvement efforts, the Technology Innovation and Confirmation program is in the process of ramping up to a stable program size based on a percentage of BPA revenues.

BPA has considered the above cost drivers in light of the comments received and has made the following changes to proposed program spending levels:

For FY 2009:

- For Power and Agency Services internal operations, proposed levels have been reduced by 3 percent.
- The Conservation Rate Credit is reduced by $4 million.
- The capital investment forecast for Conservation is reduced by $10 million.

These changes result in a decrease of roughly $8 million from the FY 2009 Power Services spending levels shown in the initial IPR. In addition, the 3 percent reduction in Agency Services also produces a decrease of $5 million for Transmission.

For FY 2010-2011:

- Conservation capital will be reduced by $18 million in FY 2010 and $10 million in FY 2011. These forecasted reductions reflect further analysis and a revised estimate of what the program can achieve, including a ramp-up period to the expected program levels in FY 2010-2011.
- We have reestablished the renewable rate credit in the forecast. This credit was proposed to be zero in the initial IPR. It has been increased to $4 million for FY 2010 and $2.5 million for FY 2011. This increase reflects the expectation that utilities are likely to need additional assistance in acquiring and using renewable resource power to serve their retail loads.
- We have modified the planned Transmission Services Capital as follows:
    - Reshaped the timing of the I-5 corridor project to reflect a more likely and achievable schedule, and
    - Increased the “lapse factor” for transmission capital from 15 percent to 17 percent. (The lapse factor is an assumption that a percentage of planned capital investment will be delayed into the subsequent rate period.)

Note: The lapse factor for all other programs except fish and wildlife and CGS remains at 15 percent. No lapse factor was applied to fish and wildlife or CGS.

The impacts to depreciation and interest expense due to changes in capital investment have been estimated in tables in the Power and Transmission sections of this document, however the final amounts will be determined in the upcoming rate cases.

Additional Review

The decisions on FY 2010-2011 program spending levels outlined here are based on the best information available. We believe that by next spring we should have additional information that may cause revisions to some program levels for FY 2010-2011. Additional information will likely become available on the following topics:

- A better understanding of BPA's role in the development of energy efficiency and renewable resources as a result of the Northwest Energy Efficiency Task Force activities, recommendations from the Northwest Power and Conservation Council's 6th Power Plan which will establish new conservation targets for the region, and a public process BPA intends to hold to discuss its role in energy efficiency;
- Better understanding of the internal costs associated with the transition to new power contracts and rates in 2012;
- More clarity on fish and wildlife costs;
- Further work on Network Open Season planning;
- Further work on BPA's asset planning and resource strategy resulting in improved estimates of realistically achievable capital spending; and
- Evaluation of the implications for BPA and the region of recent events in global financial markets and indications of a severe economic downturn.

The decisions outlined here will be the basis for our initial rate proposals. We intend to hold a subsequent, abbreviated program review next spring to reconsider the program levels in light of the increased information available at that time.

The following tables display the proposed spending levels for Power and Transmission Services by major categories. These estimates include Agency Services direct costs and allocations in support of each of the programs.

FY 2010-11 Power Expenses Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Columbia Generating Station O&M	269,200	269,200	0	365,000	365,000	0
Corps & Reclamation O&M for Hydro	280,700	280,700	0	296,461	296,461	0
Long Term Generation Program	31,889	31,889	0	32,343	32,343	0
Power Purchases incl DSI Monetized Power	327,189	*	*	404,795	*	*
Residential Exchange Payments/Other	221,426	*	*	220,445	*	*
Renewables (incl rate credit)	41,588	45,588	4,000	43,438	45,938	2500
Generation Conservation (including	87,088	87,088	0	86,722	86,722	0
Internal Operations	134,609	135,627	1,018	138,857	139,910	1053
Post-Retirement Contribution	15,598	15,598	0	16,071	16,071	0
Transmission Purchases, Reserve/Ancillary	176,393	*	*	177,043	*	*
Fish & Wildlife/USF&W/Planning Council	263,541	263,541	0	270,618	270,618	0
Amortization/Depreciation	204,001	*	*	216,916	*	*
Non-Federal Debt Service	556,184	*	*	577,064	*	*
Net Interest Expense	177,657	*	*	194,291	*	*
Other – Colville Settlement, Non-Operating	25,746	25,746	0	28,082	28,082	0
Total	2,812,809	1,154,977	5,018	3,068,146	1,281,145	3,553

*These will be determined in the upcoming rate case.

FY 2009 Power Expenses Summary

(As reported in the 2009 Power Close-Out Report)

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	**FY 2010**	**FY 2010**	**FY 2010**	**FY 2011**	**FY 2011**	**FY 2011**
Columbia Generating Station O&M	269,200	269,200	0	365,000	365,000	0
Corps & Reclamation O&M for Hydro	280,700	280,700	0	296,461	296,461	0
Long Term Generation Program	31,889	31,889	0	32,343	32,343	0
Power Purchases incl DSI Monetized	327,189	*	*	404,795	*	*
Residential Exchange Payments/Other	221,426	*	*	220,445	*	*
Renewables (incl rate credit)	41,588	45,588	4,000	43,438	45,938	2,500
Generation Conservation (incl ratecredit)	87,088	87,088	0	86,722	86,722	0
Internal Operations	134,609	135,627	1,018	138,857	139,910	1,053
Post-Retirement Contribution	15,598	15,598	0	16,071	16,071	0
Transmission Purchases,	176,393	*	*	177,043	*	*
Fish & Wildlife/USF&W/Planning Council	263,541	263,541	0	270,618	270,618	0
Amortization/Depreciation	204,001	*	*	216,916	*	*
Non-Federal Debt Service	556,184	*	*	577,064	*	*
Net Interest Expense	177,657	*	*	194,291	*	*
Other–Colville Settlement, Non-Op Gen	25,746	25,746	0	28,082	28,082	0
Total	2,812,809	1,154,977	5,018	3,068,146	1,281,145	3,553

FY 2010-11 Power Capital Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	**FY 2010**	**FY 2010**	**FY 2010**	**FY 2011**	**FY 2011**	**FY 2011**
Corps of Engineers/Bureau of Reclamation	183,200	183,200	0	199,200	199,200	0
Fish & Wildlife	70,000	70,000	0	60,000	60,000	0
Conservation	56,000	38,000	(18,000)	56,000	46,000	(10,000)
CGS	73,600	73,600	0	99,900	99,900	0
CRFM	88,000	88,000	0	96,000	96,000	0
17% Lapse Factor [1/]	(36,150)	(36,150)	0	(38,550)	(38,550)	0
Total Capital	280,700	280,700	(18,000)	296,461	296,461	(10,000)

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2009 Power Capital Summary

(As reported in the 2009 Power Close-Out Report)

$ in Thousands	2009 in WP-07 Rate Case	Supplemental Rate Case	Initial IPR	Final IPR	Change Between Initial IPR and Final IPR
Description	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**
Corps of Engineers/Bureau of Reclamation	137,000	137,000	154,950	154,950	0
Fish & Wildlife	36,000	36,000	50,000	50,000	0
Conservation	32,000	32,000	42,000	32,000	-10,000
CGS	27,700	27,700	96,700	96,700	0
CRFM	62,400	62,400	63,000	111,000	48,000
15% lapse factor[1/]			(29,813)	(28,313)	1,500
Total Capital	295,100	295,100	376,837	416,337	39,500

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2010-11 Transmission Expense Summary

$ in thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Transmission Description	**FY 2010**	**FY 2010**	**FY 2010**	**FY 2011**	**FY 2011**	**FY 2011**
Transmission Operations	**120,405**	**123,084**	**2,679**	**122,661**	**125,434**	**2,773**
System Operations	56,586	56,573	(13)	57,511	57,497	(14)
Scheduling	10,308	9,423	(885)	10,784	9,868	(916)
Marketing	18,836	19,500	664	19,538	20,225	687
Business Support (Including Internal Support)	34,675	37,588	2,913	34,828	37,844	3,016
Transmission Maintenance	**125,717**	**125,896**	**179**	**130,687**	**130,873**	**186**
System Maintenance	121,919	122,099	180	126,691	126,877	186
Environmental Operation	3,797	3,797	0	3,996	3,996	0
Transmission Engineering	**26,503**	**26,500**	**(3)**	**28,014**	**28,011**	**(3)**
Agency Services	**62,640**	**58,779**	**(3,861)**	**62,936**	**58,940**	**(3,996)**
Post-Retirement Contribution	**15,598**	**15,598**	**0**	**16,071**	**16,071**	**0**
Transmission Acquisition/Ancillary Services (3rd Party Sources)	**18,359**	**18,371**	**12**	**18,359**	**18,371**	**12**
Other Income, Expenses and Adjustments	**(2,000)**	**(2,000)**	**0**	**(2,000)**	**(2,000)**	**0**
Non-Federal Debt Service	**5,890**	*	*	**4,690**	*	*
Interest Expense	**150,623**	*	*	**168,664**	*	*
Amortization/Depreciation	**200,810**	*	*	**211,538**	*	*
Total	**724,546**	**366,228**	**(994)**	**761,620**	**375,700**	**(1,028)**

*These will be determined in the upcoming rate case.

FY 2010-11 Transmission Capital Summary

$ in Thousands	**Initial IPR**	**Final IPR**	**Change**	**Initial IPR**	**Final IPR**	**Change**
Transmission Program	**FY 2010**	**FY 2010**	**FY 2010**	**FY 2011**	**FY 2011**	**FY 2011**
Main Grid Projects	155,905	150,587	(5,318)	221,346	209,346	(12,000)
Area & Customer Service Projects	31,714	31,714	0	6,256	6,256	0
Upgrades & Additions	91,108	95,710	4,602	107,471	112,585	5,114
System Replacement Projects	134,494	134,494	0	138,423	138,423	0
Environment Projects	5,530	5,530	0	5,752	5,752	0
Customer Financed/Credits	90,165	90,165	0	102,287	102,287	0
Total Indirect Capital	86,100	87,442	1,342	88,696	96,243	7,547
17% Lapse Factor	(89,551)	(100,249)	(10,698)	(101,324)	(103,773)	(2,449)
Total Capital	505,465	495,393	(10,072)	568,907	567,119	(1,788)

Response to General Comments

Many of the comments received during the public comment period on the overall FY 2010-2011 program spending levels relate to BPA's processes, rate levels and decision making rather than to specific programs. More broadly based comments are addressed below.

1. Potential rate increases, cost controls and a budget cap:

- Tacoma Power made the following comments: **Potential Rate Increases: "**The potential rate impact of the proposed agency-wide spending levels for FY 2010-2011 is alarming." **Cost Controls:** "We urge BPA to further review areas under your control where costs could be reduced. Ensure the FY 2010-2011 cost proposal is being developed with the mindset for keeping costs in check and not funding unjustified projects and programs that appear on an organization's 'wish list.' The budgets for each workgroup appear to be created as individual silos and there does not appear to be any cross-agency prioritization. . . . . (We) recommend BPA now perform some cross-agency prioritization and reduce these increases by not funding low-priority projects and scaling some of the others." ….**Budget Philosophy**: "No funding goal (or percentage increase limit) seems to be established from one year to the next and the proposed FY 2010-2011 budget increases are substantial. BPA should exercise diligence to identify projects or program areas where costs could be reduced to offset some of the impacts of the known large cost drivers. . . . BPA should continue to look for creative ways to reduce the impacts from the primary cost drivers by confirming that these (power) funding levels are required. These Agency Services costs need to be reduced, rate of inflation or lower."
- The Joint Public Power group made the following comments. "We suggested in our comments on the 2009 IPR comments that BPA adopt an overall spending limit . . . . BPA did not respond to our suggestion in closing out the FY2009 IPR process regarding the need for an overall budgetary cap. There is no evidence of an overall spending limit…BPA should guard against raising its cost structure to the point where it may have competitiveness problems if market energy prices decline in the future…BPA should take into account cost pressures faced by its customers. . . . If secondary revenues don't stay high, BPA could easily be looking at a 20-25% (power) rate increase with the proposed budgets. Agency Services spending increases should be held to the rate of inflation." "We would still like a response to the suggestion. . . . WAPA's MOA with its utilities. . . could serve as a possible model …"

Response: BPA recognizes that utility customers have concern over the rate level that BPA establishes to recover its costs. Therefore, in the development phase of these proposed spending levels, BPA prioritized and outlined the programs and projects included in proposed spending. In its review, BPA did not employ a cost review standard for determining whether a project or program is justified or not, but rather, the resulting cost of a given project or program is driven by a rise in program requirements, including significant infrastructure improvement and obligations to meet new regulatory requirements. Such projects and programs are not the result of a "wish list" but are the result of BPA meeting its federal public purpose. Program requirements cannot be met without increasing Power and Transmission spending, as well as spending in support organizations that play an integral role in accomplishing and completing the work. While it is likely these costs will result in some level of increase in Power and, possibly, Transmission rates, we believe this level of spending is necessary to avoid significant costs and/or reductions in long term reliability. We will, however, re-assess these program levels during FY 2009, prior to developing final rate proposals.

BPA has not developed an overall budgetary cap or established a requirement to hold increases to some level, such as the rate of inflation, and does not believe it is appropriate to do so. Setting arbitrary ceilings can be counter productive and result in decisions and program levels that have negative impacts over the long term that far outweigh short-term savings. In developing program levels, BPA uses an Integrated Financial Planning Process that charts the development, approval and implementation of program levels and cost estimates. This process links BPA's internal spending level development and pre-rate development with the IPR, which allows for open public participation.

Within this framework, BPA believes it is important that the spending level development process include flexibility, allowing BPA to respond to changing circumstances and/or requirements. This flexibility was essential in determining the program levels proposed in the initial IPR for FY 2010-2011. In the development process, for example, BPA recognized that Power Services has effectively had a cap on Power internal operating costs and has been absorbing inflation for seven years. Despite the success of the Efficiency Project Improvement Processes (EPIP), which have helped BPA mitigate cost pressures in many areas, many costs actually have been deferred. This deferral has contributed to the cost pressure BPA now faces. These pressures are such that we can no longer successfully sustain flat costs while maintaining reliability and meeting other obligations. BPA also took into consideration the numerous new initiatives and drivers that are likely to require cost increases. While BPA certainly considers the impact of program levels on its customers, it also tries to find the right balance between low cost and the other "pillars" in its strategy to provide system reliability, environmental stewardship and regional accountability.

One comment suggested that an agreement such as the one that Western Area Power Marketing Administration's Rocky Mountain and Upper Great Plains Region (WAPA) has with its utility customers could be used as a model for implementing more thorough customer involvement in the front end of the budget process. WAPA, Bureau of Reclamation, and the US Army Corps of Engineers (the Agencies) executed a memorandum of understanding regarding the Pick-Sloan Missouri Basin Program/Fryingpan-Arkansas Project Work Program Review (Program Review MOU) with three preference utility customer associations.

This Program Review MOU is intended to promote active participation, communication and coordination among the Agencies and the preference associations and identifies agreed-upon schedules and formats for the Agencies to provide financial and work program information. It provides for a Technical Committee and an Executive Committee, both made up of representatives from each of the Agencies and each of the customer associations. Under the MOU, the Agencies provide the preference associations the following information, in a specified format:

- Expense budgets compared to actual expenses for the completed year, with explanations for significant differences (e.g., +/- 10%);
- Annual expenses for two completed years, the current year, and five future years' estimates, with explanations for significant differences;
- A list of cumulative capital expenditures, current year capital investments, and five future years' estimates, including replacement projects;
- FTE for two prior years, current year, and five future years' estimates;
- Comparison of indirects/overheads for two prior years, current year, and five future years' estimates, with explanations of significant differences;
- Most current Construction and Rehabilitation Program 10-year Plan, plus reporting on significant projects that may impact the Power Repayment Study or be of interest to the Technical Committee;
- Current program status report, e.g., overview of critical issues, budget line items, proposed studies, plan or program changes since the last briefing, etc.; and
- As applicable, customer advanced funding and access to receipts funding separately from appropriations, revolving fund, etc.

The Technical Committee meets at least twice per year to review and exchange financial and cost data. The Agencies are supposed to respond timely to the issues raised by the preference associations over future spending activities within the limits of the Agencies' authorities to disclose such information. Upon written notice, a preference association may request additional information and, subject to applicable federal law and regulations, shall have the right to review relevant records at the offices of the Agency. Disputes or disagreements regarding matters involving the Technical Committee may be referred to the Executive Committee for review, and disputes or disagreements regarding issues for the Executive Committee may be referred to the head of the Agency(ies). The appropriate Agency head shall respond to the issue within 20 working days.

BPA believes the Cost Review construct (now called the Integrated Business Review) described in the Regional Dialogue Policy provides all of BPA's customers and constituents a high level of transparency, including most of the same type of financial information provided for review under the Program Review MOU, and much of it in greater detail. BPA considered a formal review process conceptually similar to the Program Review MOU, called the Cost Management Group (CMG), in the Regional Dialogue. The proposed CMG had a defined number of representatives of customer and non-customer interest groups participating. However, BPA found this was one of the major problems with the CMG. As stated in the Long-Term Regional Dialogue Record of Decision (ROD), "one of the CMG's major stumbling blocks is it would represent a limited membership. While there are groups of stakeholders with similar relationships with BPA, they may have widely divergent interests and views of BPA costs. . . . As NRU notes, 'based on previous discussion and experience, it would likely be impossible to reach a broad based regional agreement regarding the size of the CMG and the proportionate representation between various stakeholder groups.'" (Regional Dialogue ROD, page 256)

The Program Review MOU provides for exchange of information that is restricted to the Agencies and the preference associations. However, as noted in the Regional Dialogue ROD, "excluding non-customers from the agency's primary cost review process is contrary to BPA's stewardship obligations because it would go a long way toward silencing non-customers. BPA needs to have the ability to receive input from constituent groups directly affected by cost decisions. These organizations can provide valuable input on the effect of spending increases and reductions. It is likely that the majority of the issues addressed in the renewables, conservation, and fish and wildlife spending, receive much non-customer attention because they affect or involve those who are doing the on-the-ground work in these areas. Creating separate forums for non-customers would result in a much more cumbersome and costly process and with little communication between the different interests. It is better, and more conducive to creating a collaborative process if all groups communicate with each other and with BPA, rather than just with BPA. . . . BPA's process does include tribes, states, environmental groups, and other stakeholders as well as customers rather than limiting it to a few customer groups." (Regional Dialogue ROD page 258)

Unlike the Program Review MOU, in the Regional Dialogue Policy BPA committed to a model which provides extensive opportunity for stakeholders as well as customers to review and give input to our forecasts of spending levels prior to finalizing them. This current IPR process is one part of the overall Integrated Business Review structure that BPA committed to in the Regional Dialogue. In IPR we have provided actual expenses, including indirects/overheads, for the prior two years, and forecasts for the current year and three additional years or through the upcoming rate period. For capital expenditures, we provided actuals for the prior two years and forecasts for the current year and five additional years. We also shared very detailed materials from various asset plans, including assessment of asset conditions and long-range capital plans. The level of detail provided in the IPR appears to be much greater than that provided under the Program Review MOU. For example, BPA provided at least eight full days of workshops and meetings on the FY 2010-2011 proposed costs, and hundreds of pages of materials, far in excess of the data called for in the Program Review MOU for most categories of costs.

The Quarterly Business Review (QBR) is the second part of the Integrated Business Review structure BPA committed to in the Regional Dialogue, and it is intended to be a forum to provide current financial forecasts, current financial results compared to forecasts, periodic updates to capital plans as they change, and information on upcoming issues that could have impact on future financial results. We will be holding the first such meeting in November. We have received input on the structure of those meetings and will solicit additional input.

In addition to information provided through the IPR and QBR processes, BPA, the Corps, and Reclamation, who manage the FCRPS hydrosystem assets through interagency Joint Operating Committees (JOCs), recognize the need for transparency and will meet with interested parties, stakeholders, and customers on an as needed basis. For example, the agencies now meet twice yearly with the Public Power Council to discuss the hydropower program financial (expense and capital budgets compared to actual costs, FTE, etc.) and operational performance (current and planned investment activities, critical maintenance accomplishments, etc.), as well as other related issues. BPA and the other agencies make a concerted effort to provide information and opportunity for customers and stakeholders to provide input.

We believe the IPR process BPA currently has and the QBR process that is being developed, though less formal than that provided by the Program Review MOU, will provide the information and transparency customers and other stakeholders are looking for, and we will continue to ask for input on how the process can be improved.

2. Levelizing Costs:

- Tacoma Power noted that "there seems to be a general theme of trying to get caught up on capital investment and maintenance. This has resulted in a front-loaded capital and maintenance program that significantly increases costs during the initial years of the program. We are asking that some levelizing take place over the next few years. . . ."

Response: As explained in the IPR workshops, the proposed capital investment levels are driven by in-depth assessments of needs through our asset management planning process and represent what BPA believes is critical to retaining reliable power generation and transmission. However, as suggested in comments, BPA has scrutinized its forecasts and made some revisions based on the recognition that the aggressive schedule for transmission and conservation capital investment may not be achievable. The final IPR levels reflect a revised schedule for one transmission capital project and an increased lapse factor applied to transmission capital (from 15 percent to 17 percent). Considering the probable need for a ramp-in period for the projected increase in conservation capital, the FY 2010-2011 conservation capital has been reduced by $18 million in FY 2010 and $10 million in FY 2011.

3. IPR Process:

- The Joint Public Power group made the following comments: A couple of changes would help in evaluating BPA's proposals: first, BPA should provide alternative packages of spending proposals for evaluation. . . .BPA made a reasonable first start at this in . . . looking at the effects of a 10% cost decrease by function . . . , but more BPA departments need to emulate the detailed analysis that BPA Public Affairs did in taking a detailed look at the impacts of spending reductions. . . . It would be useful and good budgetary practice to have BPA present a formal business case for new incremental spending proposals where BPA would calculate the benefit and the rate of return associated with the incremental spending, so that the proposal could be better evaluated.

- Tacoma Power commented that there should be clear cost-benefit analysis performed and provided as part of the IPR process. . . . BPA must establish a reliable practice to control costs and should do so with significant input from its contractual customers through the IPR process.

Response: We appreciate feedback on our first agency wide IPR process. We expect the next full IPR process to begin in the spring of FY 2010 and will take these comments into account as we plan for that process.

We will also begin Quarterly Business Review (QBR) meetings this year and expect to use these meetings to provide updates of current expense and capital spending compared to forecasts, as well as to notify customers and constituents of current or upcoming issues that could impact BPA's financial situation.

4. Tier 2 Product:

- The Joint Public Power group noted that any costs associated with the development of Tier 2 products should not be included in rates and paid for under the current subscription contracts.

Response: While we understand customer interest in this issue, this is a rate-making issue and should be addressed in the upcoming Power rate case rather than in the IPR forum.

Structure of This Report

Sections 2 through 4 of this document focus on each of the program areas identified in the workshop process and provide detailed information for the following four issues:

1) The initial IPR spending levels compared with the FY 2007-2009 rate case average,
2) A short description of what is included in the associated costs,
3) Comments received on the program area, and
4) Final decisions on cost levels for the initial rate proposal, addressing comments received.

Section 2 addresses Power Services costs, including the Fish and Wildlife Program, the Lower Snake River Compensation Plan, and Energy Efficiency/Conservation, which are fully direct-charged to Power Services. Section 3 addresses Transmission Services costs. The majority of Agency Services costs are addressed concurrently with the Power and Transmission programs they support. Section 4 addresses some remaining some Agency Services Programs as well as the Technology Innovation and Confirmation program, which impacts both Power and Transmission.

Section 2

POWER SERVICES

The first two summary tables below provide the change in FY 2010-2011 expense and capital forecasts from the Initial IPR to the Final IPR. The third and fourth tables displays the FY 2009 expense and capital forecasts from the original FY 2007-2009 rate proposal, the initial IPR, and the Final FY 2009 Power IPR Report.

FY 2010-11 Power Expenses Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Columbia Generating Station O&M	269,200	269,200	0	365,000	365,000	0
Corps & Reclamation O&M for Hydro	280,700	280,700	0	296,461	296,461	0
Long Term Generation Program	31,889	31,889	0	32,343	32,343	0
Power Purchases incl DSI Monetized Power	327,189	*	*	404,795	*	*
Residential Exchange Payments/Other	221,426	*	*	220,445	*	*
Renewables (incl rate credit)	41,588	45,588	4,000	43,438	45,938	2,500
Generation Conservation (incl ratecredit)	87,088	87,088	0	86,722	86,722	0
Internal Operations	134,609	135,627	1,018	138,857	139,910	1,053
Post-Retirement Contribution	15,598	15,598	0	16,071	16,071	0
Transmission Purchases, Reserve/Ancillary	176,393	*	*	177,043	*	*
Fish & Wildlife/USF&W/Planning Council	263,541	263,541	0	270,618	270,618	0
Amortization/Depreciation	204,001	*	*	216,916	*	*
Non-Federal Debt Service	556,184	*	*	577,064	*	*
Net Interest Expense	177,657	*	*	194,291	*	*
Other–Colville Settlement, Non-Op Gen	25,746	25,746	0	28,082	28,082	0
Total	2,812,809	1,154,977	5,018	3,068,146	1,281,145	3,553

*These will be determined in the upcoming rate case.

FY 2010-11 Power Capital Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Corps of Engineers/Bureau of Reclamation	183,200	183,200	0	199,200	199,200	0
Fish & Wildlife	70,000	70,000	0	60,000	60,000	0
Conservation	56,000	38,000	(18,000)	56,000	46,000	(10,000)
CGS	73,600	73,600	0	99,900	99,900	0
CRFM	88,000	88,000	0	96,000	96,000	0
17% Lapse Factor [1/]	(36,150)	(36,150)	0	(38,550)	(38,550)	0
Total Capital	280,700	280,700	(18,000)	296,461	296,461	(10,000)

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2009 Power Expenses Summary

(As reported in the 2009 Power Close Out Report)

$ in thousands	2009 in WP-07 Rate Case	Supplemental Rate Case	Initial IPR	Final IPR Forecast	Change between Initial IPR and Final IPR
Power Program	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**
Columbia Generating Station O&M	242,842	274,342	293,700	293,700	0
Corps & Reclamation O&M for Hydro Projects	248,173	248,173	261,600	261,600	0
Long Term Generation Program	25,751	31,864	31,613	31,522	(91)
Renewables (incl rate credit)	41,917	53,414	43,955	43,955	0
Generation Conservation (including Conservation Rate Credit)	70,347	79,414	84,526	80,526	(4,000)
Internal Operations	111,566	111,566	125,030	121,018	(4,012)
Pension & Post-Retirement Benefits	15,375	15,375	15,277	15,277	0
Transmission Purchases, Reserve/Ancillary Services	177,525	177,515	176,073	176,073	0
Fish & Wildlife/USF&W/NWPCC	173,353	173,367	229,439	229,439	0
Other – Colville Settlement, Non-Operating Generation	24,649	21,049	27,413	27,413	0
Total	2,698,421	2,615,184	2,730,011	2,717,549	(8,103)

FY 2009 Power Capital Summary

(As reported in the 2009 Power Close Out Report)

$ in Thousands	2009 in WP-07 Rate Case	Supplemental Rate Case	Initial IPR	Final IPR	Change Between Initial IPR and Final IPR
Description	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**
Corps of Engineers/Bureau of Reclamation	137,000	137,000	154,950	154,950	0
Fish & Wildlife	36,000	36,000	50,000	50,000	0
Conservation	32,000	32,000	42,000	32,000	(10,000)
CGS	27,700	27,700	96,700	96,700	0
CRFM	62,400	62,400	63,000	111,000	48,000
15% lapse factor[1/]			(29,813)	(28,313)	1,500
Total Capital	295,100	295,100	376,837	416,337	39,500

1/ Excludes CGS, CRFM, Fish & Wildlife

A. COLUMBIA GENERATING STATION O&M

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
269.2	269.2	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
365.0	365.0	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
73.6	73.6	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
99.9	99.9	0

BPA pays the costs of Energy Northwest's Columbia Generating Station (CGS) nuclear power plant. Energy Northwest (EN) has continued to focus on equipment obsolescence, reliability and plant performance. EN management believes additional investments are necessary to improve safety, reliability and performance. The plant's performance indicators have been low when measured against criteria set by the Institute of Nuclear Power Operations (INPO), but capacity factors have been good.

Comments Received:

- Tacoma Power commented they are concerned with the proposed $27M increase for 2010 and $123M increase for 2011... (and) request BPA to continue efforts to influence the reduction of the proposed CGS budget.
- The Joint Public Power Group made the following comments: EN should be aware of the importance of its Long Range Plan (LRP) for BPA ratemaking... It would be most effective if the results of the LRP could set a cap on spending in the years beyond the current budget year. Also, it would be very helpful if the timing of the LRP and the BPA IPR could be better synchronized so that BPA could have reliable information as BPA and the customers go into the IPR process. In addition, BPA and EN should further explore the costs and benefits of moving CGS financial reporting to BPA's fiscal year.

Response: EN believes that the CGS program levels reflect the need to continue improvement efforts and ensure sustained high performance. The increased funding EN has identified for FY 2010-2011 is designed in general to address:

1) Deferred maintenance issues,
2) Equipment obsolescence and reliability, and

3) Performance improvement initiatives.

These investments should result in improved overall performance of CGS.

BPA has discussed, and will continue to discuss, with EN the need for cost effective, safe, reliable operation of the Columbia Generating Station to benefit the ratepayers of the Northwest. Safety and reliability are paramount goals, but it is essential that we meet those goals in the most cost-effective way possible. BPA is concerned about the rapid rate of increase in costs for CGS operations. In conjunction with Energy Northwest management, a set of performance indicators has been developed. We are actively tracking these indicators on a quarterly basis and will make this information available to the public. This tracking should help ensure that these major increases in spending actually yield the improvements they are intended to produce.

EN management has also proposed to develop a long range plan with significantly increased rigor such that it would provide greater confidence to BPA and others that actual results will be consistent with the plan. We also understand the EN Board has hired independent counsel to evaluate CGS's long range plans and budgets in terms of addressing significant station needs. We believe this is an appropriate step and encourage its continued implementation. We would be interested in working with the Board to see how we could benefit from the counsel of any independent review the Board undertakes. Finally, BPA is considering seeking independent counsel from individuals with significant nuclear plant executive management and operations experience in order to be able to complement our on-site Richland staff's experience. The focus of any contracted additional executive nuclear expertise will be to assure our budget review and oversight authority is executed in a manner that will promote the safe, reliable and cost-effective operation of CGS consistent with the project agreements. We also intend to continue to urge the EN Board to adopt the overarching principle we proposed to the Board last year. As stated below, this principle seeks to provide greater alignment throughout our organizations through focusing on the complementary nature of our missions. That principle is as follows:

> "BPA and ENW are committed to long-term, safe, reliable operation of CGS accomplished at the lowest reasonable cost necessary to achieve those objectives. It is also our objective to integrate CGS with the Federal Columbia River Power System and to achieve optimum utilization of the resources of that system taken as a whole and to achieve efficient and economical operation of that system."

BPA and customers have emphasized the importance of a credible Long Range Plan and the ability of EN to live to that plan. EN produced and updated an LRP in the spring of 2008 in conjunction with the FY 2009 budget. EN has committed to living within the costs identified in the plan, barring any unforeseen regulatory requirements. EN has revised its budget preparation cycle (long range plan) by advancing it by two months. This will allow time for meaningful customer review and input of the CGS budget before it is included in future IPR reviews. EN is exploring options for changing the EN fiscal year to coincide with BPA's fiscal years; however, it is not clear if the benefits of such a move would justify the costs.

Decision: No change to the planned CGS expense or capital forecast for FY 2010-2011.

B. CORPS AND RECLAMATION O&M

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
280.7	280.7	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
296.5	296.5	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
183.2	183.2	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
199.2	199.2	0

BPA works with the U.S. Army Corps of Engineers and the Bureau of Reclamation to implement funding for both operations and maintenance (O&M) activities at 31 hydro electric facilities throughout the Northwest and to ensure implementation of all regionally cost-effective system refurbishments and enhancements. BPA's Enterprise Process Improvement Project (EPIP) included a major asset management planning effort that included Federal hydro facilities. Significant drivers of change affecting Corps and Reclamation O&M include the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) compliance requirements, non routine extraordinary maintenance requirements, and Biological Opinion (BiOp) requirements. BPA expects O&M spending to rise at roughly the rate of inflation (except for non routine extraordinary maintenance activities such as the Grand Coulee Dam Third Powerhouse rehabilitation and other items mentioned above.)

Columbia River Fish Mitigation Project (CRFM) includes the power portion of investment funded by Corps of Engineers appropriations for investment on mitigation efforts for fish and wildlife on the Federal Columbia River dams. BPA becomes obligated to repay the power portion of the costs to the US Treasury at the time the investment is considered complete and placed into service. While the forecast of total investment from FY 2007 through 2011 has not changed significantly, the Corps provided an updated forecast reflecting a change in the expected timing for investment being placed into service, with less than forecast going into service in FY 2007 and considerably more expected in FY 2008 than forecast in the WP-07 rate case.

Comments Received:

- The Joint Public Power group made the following comments: While improvement is always possible, it appears that the Integrated Business Management Model developed by the Corps, Reclamation and BPA has resulted in a fairly rigorous asset-based planning and management program. . . . The ramp up of capital expenditures continues to be significant. . . . The agencies should be encouraged to broaden their supplier network so they are not captive to a small number of suppliers. . . . (T)he agencies should be encouraged to take steps to reduce or eliminate inefficient O&M, rather than just escalating O&M costs by a fixed amount.

- Montana Northwest Power and Conservation Council members commented that funding for an additional turbine at Libby should be removed.
- Tacoma Power noted that BPA should exercise diligence to scale back some initiatives and stretch out implementation to offset the impacts of proposed asset management initiatives.
- Affiliated Tribes of Northwest Indians (ATNI) commented that funding for FCRPS cultural resources program must be increased, and they are concerned about the Corps not being able to finish its work with the 15-year period or by 2012.

Response: BPA, the Corps, and Reclamation developed the hydro asset planning process to ensure the hydro generating assets are operated, maintained and invested successfully to ensure benefits to the region continue over the long term. Low cost power, power reliability, and trusted stewardship are the three objectives guiding the asset planning process, and the agencies are constantly challenging themselves to maximize them. Equipment health and condition, operational requirements, financial performance, and risk and consequences are continually evaluated and assessed in determining the expense and capital resource requirements for the program. As noted in IPR workshops, the hydro system is aging and requires extensive investment to ensure its continued long term performance. Also, new regulatory requirements associated with the updated Biological Opinion and WECC/NERC reliability compliance are requiring additional O&M expense resources to ensure the agencies are in compliance. The agencies will continue to exercise diligence in managing the program by evaluating capital investments and O&M expense requirements to ensure adequate long term performance and benefits of the hydrosystem.

As encouraged in the comments received, the agencies will strive to ensure the broadest number of suppliers is available to meet the hydrosystem's needs, consistent with government procurement practices. For example, the Corps recently met with major hydropower contractors to understand how contracts could be written to solicit more interest from them. Additionally, the agencies are continually evaluating business decisions to ensure revenue is maximized while operating and maintaining a safe, low cost, and reliable system.

Regarding cultural resources activities, the funding levels for such activities across the FCRPS were derived from the System Operations Review (SOR) and agreed to by the Corps, Reclamation, BPA, and the tribes. The term of the agreed-upon funding was for 15 years, which ends in 2012. A number of changes in the funding levels for Cultural Resources will be addressed during development of a new agreement for funding that will take effect in 2012, after the 15-year original term is completed. The agencies expect to begin work on developing a new funding agreement during FY 2009.

Regarding the comment that there is no scientific basis for funding an additional turbine at Libby to support Kootenai River sturgeon, the Libby 6th unit was identified as a potential project for planning purposes only and was listed that way while describing the system asset planning process. There was no funding included in the plan for this work as it did not meet hydro capital investment criteria; it was merely identified as a potential project. If a decision were to be made that a 6th unit at Libby was necessary due to ESA considerations, funding would have to come by displacing other capital projects in the plan.

Decision: No change to the planned Corps and Bureau of Reclamation expense or capital forecast for FY 2010-2011.

C. LONG-TERM GENERATING PROGRAM

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
31.9	31.9	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
32.3	32.3	0

This program consists of BPA's long-term acquisition contracts for output from generating resources such as Cowlitz Falls, Billing Credits Generation, Wauna Co-generation project, Elwah Dam, Idaho Falls Bulb Turbine, and Clearwater Hatchery Generation. Most of the expenses associated with the long-term generating projects are based on energy production at the generating units and, therefore, are offset by revenues. There is little opportunity for improvement because prices are fixed by contract.

Comments Received:

None

Decision: No change to the planned Long-Term Generation Project forecast for FY 2010-2011.

D. ENERGY EFFICIENCY & CONSERVATION

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
87.1	87.1	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
86.7	86.7	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
56.0	38.0	18.0
FY 2011		
Initial IPR	**Final IPR**	**Change**
56.0	46.0	10.0

FY 2009 Expense			
Original WP-07	**Initial IPR**	**Final IPR**	**Change**
70.3	84.5	80.5	(4.0)
FY 2009 Capital			
Original WP-07	**Initial IPR**	**Final IPR**	**Change**
32.0	42.0	32.0	(10.0)

(As reported in the 2009 Power Close Out Report)

BPA's Energy Efficiency and Conservation program is designed to capture the anticipated 35 to 40 percent increase in public power's share of the region's conservation target in the FY 2010-2011 period (i.e., 70 aMW per year).

Comments Received:

- Idaho Conservation League commented that the IPR should include additional support for efficiency/conservation programs.
- Tacoma Power stated it does not support increases in conservation spending that would affect the Tier 1 rate.
- The Joint Public Power group raised a concern about spending increases. The region has been able to achieve conservation under current levels. They would be more comfortable with the spending if they knew what would be included in new long-term contracts.
- Columbia Inter-Tribal Fish Commission (CRITFC) supports full funding of conservation. BPA should expand conservation programs as much as possible.

Response: Tiered rates will not start until FY 2012, which is beyond the scope of this IPR. BPA's post-2011 energy efficiency costs will be included in Tier 1 rates as outlined in the Final Long Term Regional Dialogue Policy (July 2007). That said, BPA has designed its proposed spending for energy efficiency to capture the anticipated 35 to 40 percent increase in public power's share of the region's conservation target in the FY 2010-2011 period (i.e., 70 aMW per year). It is uncertain what level of utility self-funding for conservation will occur during this time. Therefore, BPA's proposed spending levels assumed that 20 percent (or 14 aMW/year) of public power's share of the regional conservation target would be delivered by utilities using their own funds. BPA also proposes energy efficiency capital spending for this period to supplement utility funding under bilateral contract arrangements. The incentives customers have, including the high water mark credits, to fund conservation themselves are not expected to be enough to ensure achievement of the cost-effective conservation targets.

There remain, however, several outstanding processes and planning areas that have not concluded at this time and need to be resolved before BPA can determine the proper level of energy efficiency capital for FY 2010-2011. These areas include:

1) The Northwest Energy Efficiency Taskforce (NEET) activities and future recommendations,
2) The Council's 6th Power Plan, which will likely establish new, higher conservation targets for the region,
3) BPA's Resource Program, and
4) BPA's public process to determine its role in energy efficiency in the post-2011 period. This last process will begin early in the 2009 calendar year.

The information acquired through these processes and plans will help BPA determine the appropriate capital funding levels for its energy efficiency program.

Despite the current lack of certainty prior to these processes BPA feels comfortable reducing the proposed capital spending by $18 million in FY 2010 and by $10 million in FY 2011. This reduction in capital assumes that utilities will deliver additional conservation savings using their own funding (i.e., 33 percent, or 23 aMW, in 2010 and 27 percent or, 19 aMW, in 2011) to guarantee higher targets are met. However, to achieve the energy efficiency targets that the agency has committed to, further reductions to the Energy Efficiency budget are not appropriate at the current time. BPA expects to have better information regarding BPA's energy efficiency program requirements before BPA considers if changes in forecasts are appropriate next spring.

Decision: No change to the planned Conservation/Energy Efficiency expense forecast for FY 2010-2011. The Capital forecast will be reduced by $18 million for FY 2010 and $10 million for FY 2011.

E. FISH AND WILDLIFE DIRECT PROGRAM

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
230.0	230.0	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
236.0	236.0	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
70.0	70.0	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
60.0	60.0	0

BPA expends ratepayer revenues in the implementation of measures addressed to the recovery of Columbia River fish listed as threatened or endangered under the Endangered Species Act (ESA) and to the mitigation of impacts to fish and wildlife from the development and operation of the FCRPS. This dual mitigation and recovery responsibility requires a comprehensive approach to implementing the Direct Fish and Wildlife Program (Direct Program) that integrates the ESA requirements of the FCRPS biological opinions from the U.S. Fish and Wildlife Service and National Oceanic and Atmospheric Administration (NOAA) Fisheries, with the broad resource protection, mitigation and enhancement objectives of the *Columbia Basin Fish and Wildlife Program* adopted pursuant to the Northwest Power Act.

BPA meets these complementary fish and wildlife mitigation and recovery objectives in the Direct Program primarily through the negotiation and award of contracts to state, federal, and tribal entities. Drivers for increased contract costs in FY 2010-2011 are new Biological Opinion requirements and the 2008 Columbia Basin Accords agreements with states and tribes on fish and wildlife costs. These additional contract commitments are to be implemented as expeditiously as possible to accomplish specific projects or program outcomes addressed to the impacts of federal hydropower development and operation in the Columbia River. Project results will be credited and accounted for as contributions toward the recovery and mitigation obligations of BPA.

Comments Received:

- **New BiOP and Fish Accords, Proposed Budget Increase:** CRITFC expressed strong support for BPA's proposal to increase its fish and wildlife funding to fully implement the MOA signed on May 2, 2008. CRITFC and BPA staffs are working to better refine the expense and capital portions of this funding. CRITFC will continue working with BPA staff in the near term to better refine these expense and capital budgets. It is their understanding that these revised budgets will be included in BPA's IPR close-out letter and incorporated into the BPA rate case analysis.
- **Cost Effectiveness, Duplication and Unnecessary Efforts:** Tacoma Power stated BPA should carefully review this proposed increase and look for duplicate efforts and items that are not required. Focus needs to be placed on choosing alternatives that provide the desired results in the most cost-effective manner.
- **Budget Management Plan, Long Term Budget Cap, Carry Over and Inflation:**
    - The Joint Public Power group made several comments.
        - First, BPA needs to develop a fish and wildlife budget management plan. Program budgets should be fixed, regardless of whether the program spent

all funds in the previous year. Excepting BiOp and MOA commitments, the establishment of funding should not create a locked-in future expectation to the budgeted funds if they are not spent in the current fiscal year.

- Second, because of the risks that operational costs will be substantially higher than expected it is imperative that BPA establish and abide by a long-term budget for the Integrated Fish and Wildlife Program costs.
- Third, BPA stated it will make a decision on how to handle unspent funds as part of the development of a budget management plan for overall program budget management, and that it plans to develop the plan this summer. Customers would like BPA to set a timetable for definition of BPA funding requirements, completion of a budget management plan and a review process for customers and other stakeholders.
- Fourth, customers are uncomfortable with the automatic inflation adjustment and would like greater detail on how and when BPA plans to address the issue of a budget cap.
- Fifth, it is imperative that BPA not only consider the recommendations made by its customers, but take action to implement these recommendations. BPA needs to set a schedule for development and implementation of a budget management plan, to address how the Northwest Power and Conservation Council Program, Memoranda of Agreement with States and Tribes, a new biological opinion, and other elements of BPA's fish and wildlife budget will be integrated and managed.

Program Review:

- The Joint Public Power group commented that customers would like to see BPA work closely with the Council to ensure a comprehensive program review that involves the Independent Scientific Review Panel. In particular, RM&E needs to undergo rigorous scrutiny. There are projects currently funded by ratepayer dollars that have little relation to the effects of hydropower construction and operation and should be funded through other sources or eliminated. The funding should be seen as comprehensive for both fish and wildlife and the proposed budget should not increase beyond its current limit.
- Washington Department of Fish and Wildlife commented that BPA should continue to support, and consider costs associated with funding the following projects: Pacific States Marine Fisheries, Commission Coded Wire Tag Project, the Smolt Monitoring Program, the Fish Passage Center, Comparative Survival Study, StreamNet, the Columbia Basin Fish & Wildlife Authority, and the Lower Snake River Compensation Program.
- Washington Governor's Salmon Recovery Office commented that BPA should consider the needs of regional salmon recovery organizations in Washington. Greater funding would enable enhanced coordination to meet the needs of the 2008 BiOp and Columbia Basin Fish Accords.

Science Review:

- The Joint Public Power group recommended that the current requirements for Independent Scientific Review Panel review should be continued for all projects funded by BPA. BPA has noted a commitment to ensuring independent science review, but needs to outline the process that guarantees this.

Economic Review:

- The Joint Public Power group supports the Independent Economic Advisory Board (IEAB) and request that it be adequately funded.

Cultural Resources:

- ATNI expressed concern whether BPA can provide more information on the cost components for how these cultural resources responsibilities (for BPA Fish and Wildlife Mitigation Program Projects) will be met for FY 2009 and elaborate on the tribal consultation/ coordination components related to these costs.

Mitigation Settlement of Southern Idaho and Albeni Falls:

- Idaho Department of Fish and Game proposed consideration of a settlement of the wildlife mitigation obligation for Southern Idaho and Albeni Falls. BPA should calculate a reasonable estimate of the value for the rate case so a settlement is not foreclosed.

Response: Because a new BiOP and Fish Accords exist, BPA has made a proposed spending increase for Fish and Wildlife Program implementation in FY 2010-2011, resulting in upward adjustment in funding from the current rate period to $230 million and $236 million, respectively. These proposed spending levels reflect the funding needed to implement both the new FCRPS Biological Opinion (BiOp) and the Columbia Basin Fish Accords (Accords) without reducing funding for other non-BiOp and/or non-Accord elements of the Program. While the proposed spending includes the funding necessary to meet Fish Accord commitments to individual Accord signatories, the spending is not broken down into individual components. In total the spending proposed is what BPA believes is necessary for meeting its individual Accord and BiOp commitments while not reducing funding for other elements of the Program.

Cost Effectiveness, Duplication and Unnecessary Efforts:

BPA continues to place a premium on enhancing Fish and Wildlife Program performance and on managing and administering contract implementation to deliver project outcomes as biologically effective results – at the lowest cost and within budget. We see this as a two-pronged undertaking:

1) The Program itself must be firmly grounded in measurable performance expectations expressed as biological and environmental objectives; and
2) Projects must be designed around discrete work elements tailored to expected outcomes that are explicitly addressed to the Program's performance objectives.

A durable and sustainable shift in Program emphasis is not an overnight undertaking; it is evolutionary, requiring the persistent attention of BPA Fish and Wildlife Division staff as well as buy in and commitment from other Fish and Wildlife Program partners such as the

Northwest Power and Conservation Council and the Fish and Wildlife co-managers. BPA will continue to examine and evaluate the current portfolio of effort to better spend existing resources even as we are developing additional projects to meet BiOp responsibilities and Accord commitments. The premise for existing, expanded, or newly initiated project commitments is the same: work supported by ratepayer funds will be evaluated on the basis of results that are a contribution toward explicit objectives. This is the basis of the performance construct upon which the Council has built the Program and BPA has based its BiOp actions.

Mitigation settlements for Southern Idaho and Albeni Falls: Mitigation settlements can be an effective strategy for meeting BPA's wildlife responsibilities under the Northwest Power Act. Durable, workable settlement agreements require the participation of all affected sovereigns with jurisdictional or management authority over fish and wildlife resources in the area affected by the FCRPS and encompassed by the terms of settlement proposed. These sovereign interests need to be representative of the broad public interest in mitigation responsibilities of BPA, and serve as a surrogate for the affected resources, to whom the mitigation obligation is actually owed. These attributes can confound the likelihood and timing of successfully negotiated agreements, and make it difficult to project and incorporate cost-estimates into future Program levels and budget planning.

As a practical matter, any successfully concluded agreement would have to occur within the limitations of BPA's financial flexibility. According to a recent BPA analysis (July 2008), BPA's available Treasury borrowing authority could be fully utilized by 2016. We are not budgeting for a wildlife agreement at this time due to uncertainty about whether negotiations can be successfully concluded, and in recognition that a potential Idaho wildlife mitigation settlement must fit within the scope of BPA's limited borrowing authority. BPA continues to explore strategies for maximizing its current borrowing authority, as well as potential new alternatives that might be developed.

Budget Management Plan, Long Term Budget Cap, Carry Over and Inflation:

BPA acknowledges that with the new BiOp and Fish Accords, and the related Program spending level increases in FY 2009, there are many new management implementation complexities. Although policies are being developed, important unanswered questions remain that will need to be addressed as we gain experience.

In coordination with the region, BPA will provide an opportunity for input and comment regarding the questions, issues, and policies surrounding the Fish and Wildlife proposed spending, including many of the comments proposed by BPA's customer representatives that will be considered in the development of this plan. Among the suggestions to be addressed in the plan are carry over of unspent funds, economic review, inflation and a long-term spending plan for the Integrated Fish and Wildlife Program. Science Review will be addressed in a separate document that is under development and will be provided to customers and other constituents for feedback.

BPA believes its future cost projections accurately reflect the range of impacts to the operation of the FCRPS related to implementation of both the new BiOp and Columbia Basin Fish Accords. Additional financial consequences relating potential outcomes associated with the BiOp litigation are too speculative to address at this time, and will be addressed as necessary in the future in base budgets. BPA has included adjustment clauses in rates in the past to address this risk, and will consider doing so in the future.

BPA customers commented that outside the BiOp and Accord commitments, unspent funds should not be carried forward nor made available for funding projects in the future. BPA believes that there is a potential for actual Fish and Wildlife Program spending to come in below the proposed spending in FY 2010, due to the ramp-up of the expanded program. This may occur because most of the new Fish Accord projects will not be in place before the end of the FY 2008 implementation period; under-spending is thus likely to continue into FY 2009 given the time needed to complete ISRP review and required permitting processes. Additionally, the FY 2009 spending projection reflects an assumption that actual expenditures for new work would occur at 75 percent of the full project budget.

This ramp-up assumption was applied for FY 2009; in actuality, many new projects have *project-year* budgets (the contract implementation period spans two fiscal years) that will spill into FY 2010, further extending the Program ramp-up period. BPA's proposed $230 million spending in FY 2010 is reflective of the funding level necessary for meeting Fish Accord and BiOp commitments, while allowing for no reduction of funding for the other non-BiOp and/or non-Accord elements of the Program. Given the potential for a more protracted ramp-up of Program spending for new BiOp and Accord commitments than expected, BPA may choose to introduce a probability distribution around this proposed spending in the formal FY 2010-2011 rate case, to model the anticipated range of uncertainty of actual spending relative to the proposed of $230 million for FY 2010.

As part of its FY 2007-2009 project funding decision BPA decided it was reasonable to carry over $8.8 million in unspent funding from the previous rate period, so as not to create a "use-it-or-lose-it" incentive. For FY 2010-2011, as it relates to projects outside the BiOp/Accords, BPA will make a decision on how to handle unspent funds as part of the development of a spending management plan for overall Program implementation planning. BPA expects to complete development of this plan during the autumn of 2008 and will provide an opportunity for Council, customer and Program stakeholder input.

BPA's FY 2009 proposed spending does not reflect an adjustment for inflation; however, BPA has proposed an annual adjustment of 2.5 percent per year starting in FY 2010. BPA agrees that with the addition of an annual inflation adjustment, the Program budget in total could function as an overall funding commitment or cap. For example, BPA does not plan to allow the general carryover of unspent funds for the non-Accord portion of the Program; those dollars would be otherwise returned to ratepayers by being kept in BPA's cash reserves. Conversely, if work can be implemented at lower than forecasted amount, flexibility from lower-than-expected contract costs may need to be used to cover potentially higher-than-forecasted needs of other projects. This approach, with the addition of the inflation adjustment, provides both flexibility and substantial certainty in making future project funding decisions within an overall established budget for FYs 2010-2011. However, longer-term, BPA's commitment under the FCRPS BiOps is to specific performance requirements and not to specific work or a set amount of money.

Customers suggested that BPA look for potential ways to reduce funding of other projects where there are duplicative efforts and/or a lack of a clear FCRPS mitigation nexus. BPA believes such an assessment is appropriate, and that it should logically occur as part of the Council's upcoming project review initiative, prior to any future solicitation for additional project proposals.

Independent Science Review: As noted earlier, BPA is committed to ensuring adequate independent science review consistent with the intent of the Science Review amendment to the Northwest Power Act. BPA, Fish Accord parties and the Council are currently drafting a white-paper outlining the process for Science Review of new project commitments in the Accords; BPA will soon be seeking customer input and feedback on this approach.

Independent Economic Advisory Board (IEAB): BPA supports the Council utilizing the IEAB for cost-effectiveness assessments, as appropriate.

Cultural Resources: Similar to prior fiscal years, BPA will continue to spend approximately $4.5 million per year in FYs 2010-2011 to meet the cultural resources requirements of the agency. Costs include compliance activities for transmission services and fish and wildlife mitigation projects, as well as the long-term funding commitments made in the System Operations Review of the FCRPS. For example, during FY 2008, the Fish and Wildlife Program (Program) directly supported two archaeologists to expedite on the ground contract actions. For FY 2009, BPA recruited an additional three archeologists dedicated to cultural resource compliance activities for Transmission Services and the Program.

As during previous years, cultural resource compliance spending in FYs 2010-2011 is part of the overall agency funding commitment for environmental assessment and protection in support of fish and wildlife mitigation and transmission projects. BPA archaeologists mostly charge their time directly to projects, but costs would total approximately $500,000 if included as a separate Program expense. In addition, some cultural resource surveys and reports are contracted out, and there are additional indirect costs associated with mitigation measures for transmission services and fish and wildlife. Environmental planning, tribal affairs, project management, and other agency staff work closely in consultation with Tribes, Tribal Historic Preservation Officers, and State Historic Preservation Officers. Although the costs of these activities are typically not attributed as a specific cultural resource expense, they are encompassed within projected program levels and expenditures.

Decision: No change was made to the planned Fish and Wildlife expense and capital forecast for FY 2010-2011. BPA will continue to examine and evaluate the current portfolio of effort, to better spend existing resources, even as we are developing additional projects to meet BiOp responsibilities and Accord commitments. BPA will develop an overall Fish and Wildlife Spending Management Plan – in coordination with the region. There will be an opportunity for input and comment to address questions, issues and policies surrounding the Fish and Wildlife proposed spending. Many of the comments proposed by BPA's customer representatives will be addressed in the development of this plan.

F. U.S. FISH AND WILDLIFE SERVICE: LOWER SNAKE RIVER FISH & WILDLIFE COMPENSATION PLAN

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
23.6	23.6	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
24.5	24.5	0

This program funds 11 hatcheries and 15 satellite facilities owned and operated by the Fish and Wildlife Service (FWS), and fisheries agencies of states of Oregon, Washington, Idaho and the Nez Perce and Shoshone-Bannock tribes and the Confederated Tribes of the Umatilla. This program is legislatively mandated to mitigate for the existence and operation of the four lower Snake River hydroelectric dams constructed in the1970s.

Comments Received:

- Washington Department of Fish and Wildlife supports the funding for the LSRCP. Note that this does not include potential future costs associated with ESA and the BiOp.
- IDFG supports the proposed LSRCP budget. BPA should recognize the need to fund hatchery programs in addition to fishery mitigation programs.
- Alaska F&W supports the funding of deferred maintenance for LSRCP hatcheries.

Response: BPA's proposed LSRCP spending reflects moderate increases in the near-term to address a backlog of non-recurring maintenance needs. Much of this non-recurring maintenance has been deferred since 2002 so as to maintain total LSRCP spending within rate case commitments.

The increase in funding is for deferred and extraordinary maintenance expenditures, and is not a permanent increase in spending for routine management, maintenance, and operations of hatchery facilities. Purposes include the avoidance of higher costs associated with addressing unexpected failure of equipment and facility infrastructure on an emergency basis, and managing the increased risk to human and fish health and safety. These risks increase as the useful life of existing equipment and infrastructure approaches and passes the threshold of biological effectiveness and cost-efficiency. Consequently, continued deferral of this maintenance could result in economic impacts that exceed the near-term savings from a deferral.

Regarding potential future additional LSRCP costs associated with ESA consultation and compliance with the FCRPS Biological Opinion, and informed by the federal hatchery review process, BPA would look first to the LSRCP cooperating parties to absorb these costs into the existing spending levels to the maximum extent possible. A related unresolved issue is that the BPA-USFWS direct funding agreement covers expense funding only (for operations, maintenance, monitoring and evaluation costs for these hatcheries). To the extent that major capital investments may become necessary, there is no funding source at this time.

The relationship between mitigation and conservation hatchery purposes, and the appropriate mix of production to support both, is beyond the scope of the IPR. However, BPA's funding responsibilities should naturally relate to activities necessary for mitigating the effects of the federal hydrosystem on fish populations. Consequently, to the extent that hatchery purposes can be segmented, BPA's responsibilities would encompass FCRPS mitigation, and not harvest augmentation.

The region continues to debate the efficacy and relative impacts of artificial production on the long-term fitness and reproductive success of native and wild stocks. Supplementation hatcheries which are operated for the purpose of rebuilding salmonid populations which have historically been depressed due to FCRPS impacts are supported at levels reflected in BPA's Fish and Wildlife Program budget commitments. Future funding for hatchery infrastructure, including expansion or reprogramming of existing capacity, will be informed by the outcome of the ongoing hatchery review process.

Decision: No change to the planned Lower Snake River Compensation Program forecast of expense and capital.

G. RENEWABLE RESOURCES

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
41.6	45.6	4.0
FY 2011		
Initial IPR	**Final IPR**	**Change**
43.4	45.9	2.5

BPA's goal for renewable resources is to ensure the development of its share of cost-effective regional renewable resources at the least possible cost to BPA ratepayers. BPA's share will be based on the regional load growth (about 40 percent) of its Public Utility customers. BPA will cover its share through power acquired by BPA from renewable resources to serve its public customers and/or renewable resources acquired by publics with or without financial assistance by BPA.

Comments Received:

- The Idaho Conservation League commented that BPA should restore renewable facilitation and use a portion to begin looking for reasonable investments in renewable resources.
- Tacoma Power stated that BPA should not increase the budget for renewable resources.
- The Joint Public Power group opposes BPA's proposal to completely remove the renewable option from the Conservation Rate Credit. They suggest that it be

ramped down gradually from $6 million today to $2 million by 2011. The renewable option should be extended to support small projects like customer-owned solar PV and it should also cover the purchase of Environmentally Preferred Power. BPA should continue to offer the $559/kw credit for solar PV. Renewable Northwest Project commented that $4 million is inadequate to meet customer needs for new renewables. BPA should continue its leadership by taking a broader approach to renewables.

- CRTIFC supports full funding of renewable resource programs.

Response: Comments received reflect opposing views, some suggesting that BPA should increase renewable resource spending and others suggesting BPA should not increase renewable spending. Joint comments submitted by the Public Power Council, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities, Northwest Generating Company and the Public Generating Pool noted that some utilities may continue to need assistance in procuring renewable resource generation in the short-term and that the signing parties opposed BPA's proposal to completely remove the Renewable Option from the Conservation Rate Credit. The joint comments suggested decreasing the Renewable Option funding levels from $6 million to $4 million in 2010 and $2.5 million in 2011. The joint comments also suggested that the Renewable Option should continue to support small-scale customer-owned renewable projects and allow the purchase of Environmentally Preferred Power.

Decision: BPA agrees that utilities will likely need additional assistance in acquiring and using renewable generation to serve their loads. Therefore, BPA will include in its FY 2010-2011 initial rate proposal, $4 million in 2010 and $2.5 million in 2011 for the Renewable Option to the Conservation Rate Credit.

H. POWER INTERNAL COSTS/ POST-RETIREMENT BENEFITS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
150.2	151.2	1.0
FY 2011		
Initial IPR	**Final IPR**	**Change**
154.9	155.9	1.0

FY 2009 Expense			
Original WP-07	Initial IPR	Final IPR	Change
126.9	140.3	136.3	4.0

(As reported in the 2009 Power Close Out Report)

Internal Operations includes Agency Services that provide support to the programs and organizations within Power Services and are either allocated to Power Services, or direct-charged to Power Services, as well as the internal operating costs of Power Services itself.

Although programs have increased in scope and responsibility, as stated earlier, Power Services has effectively had a cap on power costs for seven years and the internal operations costs in 2008 are virtually the same as they were in 2001. The deferral of costs creates cost pressures such that Power can no longer sustain flat costs. Increases over the 2001-2008 levels are necessary for FY 2009 through 2011 because of greater wind integration efforts than expected, greater-than-expected costs for Regional Dialogue contract and tiered rates work, greater-than-planned resource acquisition efforts, and increased IT, Supply Chain, Legal, Financial and other activities necessary to achieve the programs describe above.

Re-organizations that were not reflected in initial IPR numbers are reflected in the final IPR numbers. These reorganizations resulted in greater efficiencies and a more accurate allocation of Business Support function costs. The result is a slight shift in allocated costs of $1 million from Transmission internal costs to Power internal costs.

There was no change in Post-Retirement Benefits.

Decision: No change to total Agency Internal Operating Costs other than $1 million shift in allocation from Transmission to Power.

COST DECISIONS TO BE MADE AS PART OF THE RATE CASE

The following section provides information on areas for which the costs will be determined in the FY 2010-2011 rate proposal. They have been included in the IPR to provide an opportunity for participants to understand the basis for these costs.

I. POWER PURCHASES, INCLUDING MONETIZED BENEFITS TO DSIS

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
327.2	*	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
404.8	*	0

* Power Purchases, including monetized benefits to DSIs, will be determined in the Final Rate Proposal.

J. TRANSMISSION PURCHASES, RESERVE/ANCILLARY SERVICES

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
176.4	*	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
177.0	*	0

* Transmission Purchases and Reserve and Ancillary Services will be determined in the appropriate rate cases.

K. RESIDENTIAL EXCHANGE PROGRAM

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
221.4	*	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
220.5	*	0

* Residential Exchange benefits will be determined in the Final Rate Proposal.

L. TOTAL NET INTEREST, AMORTIZATION/DEPRECIATION AND NON-FEDERAL DEBT SERVICE

$ millions

Net Interest

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Power	177.7	176.1*	(1.6)
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Power	194.3	192.0*	(2.3)

Amortization/Depreciation

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Power	204.0	197.5*	(6.5)
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Power	216.9	208.1*	(8.8)

Non-Federal Debt Service

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Power	556.2	556.2*	0
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Power	577.1	577.1*	0

*These are a very preliminary estimates provided for information only. The final amount will be determined in the rate case and could be considerably different due to such things as updated actual 2008 data.

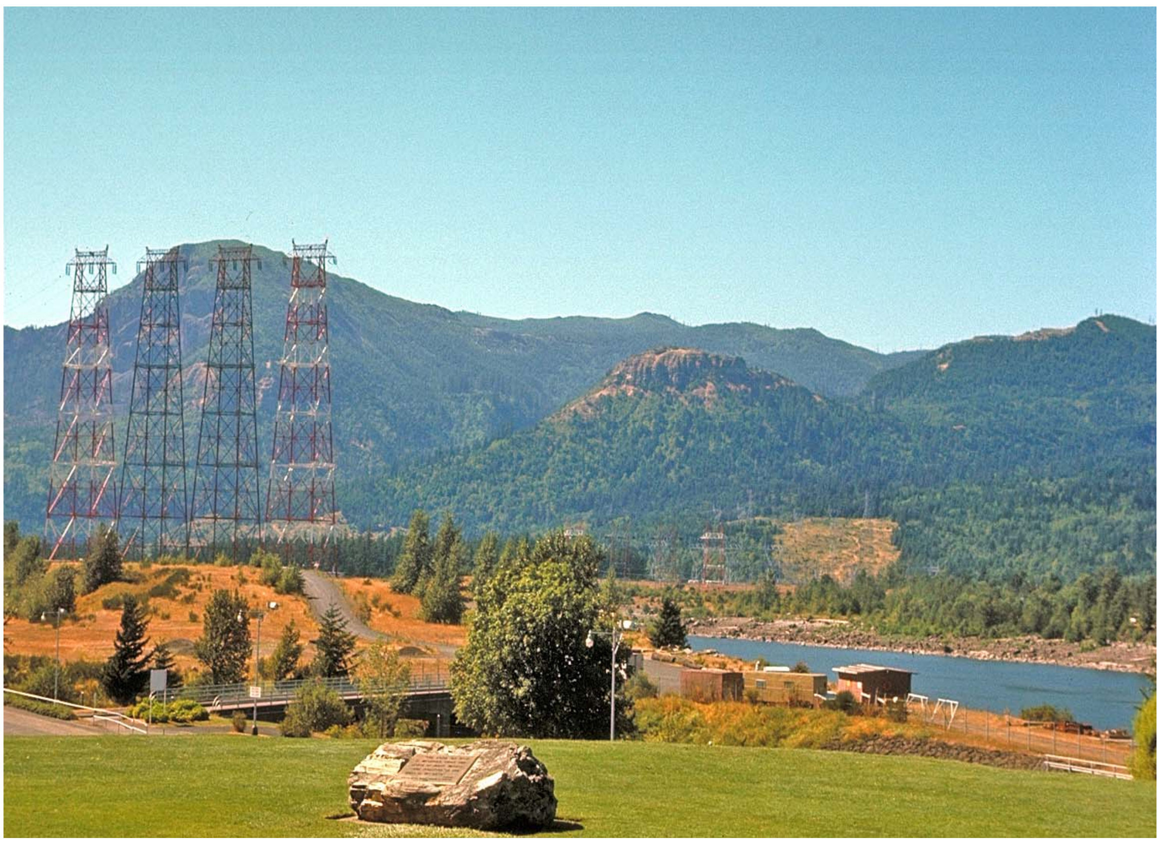
Decision: Changes since the initial IPR numbers reflect the decisions described above related to the decreased Conservation capital for FY 2010 and 2011. Other changes that affect the current estimates are revised estimates of FY 2008 investments and revised reserves estimates resulting in different interest earnings assumptions. The final levels of these forecasts will be determined in the final rate proposal.

M. DEBT MANAGEMENT

Debt management issues are not decided in the IPR. BPA's development of assumptions and decisions on debt management are rate case issues and will be discussed in that forum. However, levels of new capital investment are an important driver of the capital recovery costs in the rate case, and new capital spending is within the scope of the IPR, as discussed above, BPA believes it is important to show the impact of past and future debt management decisions in the IPR since they impact power rates. This IPR final report is intended to portray BPA's current thinking on these issues; it does not make any decisions associated with debt management issues other than new capital spending levels.

Section 3

TRANSMISSION



FY 2010-11 Transmission Expense Summary

$ thousands

Transmission Description	Initial IPR FY 2010	Final IPR FY 2010	Change FY 2010	Initial IPR FY 2011	Final IPR FY 2011	Change FY 2011
Transmission Operations	**120,405**	**123,084**	**2,679**	**122,661**	**125,434**	**2,773**
System Operations	56,586	56,573	(13)	57,511	57,497	(14)
Scheduling	10,308	9,423	(885)	10,784	9,868	(916)
Marketing	18,836	19,500	664	19,538	20,225	687
Business Support (Including Internal Support)	34,675	37,588	2,913	34,828	37,844	3,016
Transmission Maintenance	**125,717**	**125,896**	**179**	**130,687**	**130,873**	**186**
System Maintenance	121,919	122,099	180	126,691	126,877	186
Environmental Operation	3,797	3,797	0	3,996	3,996	0
Transmission Engineering	**26,503**	**26,500**	**(3)**	**28,014**	**28,011**	**(3)**
Agency Services	**62,640**	**58,779**	**(3,861)**	**62,936**	**58,940**	**(3,996)**
Post-Retirement Contribution	**15,598**	**15,598**	**0**	**16,071**	**16,071**	**0**
Transmission Acquisition/Ancillary Services (3rd Party Sources)	**18,359**	**18,371**	**12**	**18,359**	**18,371**	**12**
Other Income, Expenses and Adjustments	**(2,000)**	**(2,000)**	**0**	**(2,000)**	**(2,000)**	**0**
Non-Federal Debt Service	**5,890**	*	*	**4,690**	*	*
Interest Expense	**150,623**	*	*	**168,664**	*	*
Amortization/Depreciation	**200,810**	*	*	**211,538**	*	*
Total	**724,546**	**366,228**	**(994)**	**761,620**	**375,700**	**(1,028)**

*These will be determined in the upcoming rate case.

FY 2010-11 Transmission Capital Summary

$ in Thousands

Power Program	Initial IPR FY 2010	Final IPR FY 2010	Change FY 2010	Initial IPR FY 2011	Final IPR FY 2011	Change FY 2011
Main Grid Projects*	155,905	150,587	(5,318)	221,346	209,346	(12,000)
Area & Customer Service Projects	31,714	31,714	0	6,256	6,256	0
Upgrades & Additions**	91,108	95,710	4,602	107,471	112,585	5,114
System Replacement Projects	134,494	134,494	0	138,423	138,423	0
Environment Projects	5,530	5,530	0	5,752	5,752	0
Customer Financed/Credits	90,165	90,165	0	102,287	102,287	0
Total Indirect Capital***	86,100	87,442	1,342	88,696	96,243	7,547
17% Lapse Factor	(89,551)	(100,249)	(10,698)	(101,324)	(103,773)	(2,449)
Total Capital	505,465	495,393	(10,072)	568,907	567,119	(1,788)

*Re-spread of I-5 Corridor
**Security Enhancements
***Change in AFUDC/Corp OH

A. TRANSMISSION OPERATIONS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
120.4	123.1	2.7
FY 2011		
Initial IPR	**Final IPR**	**Change**
122.7	125.4	2.8

Transmission Operations consists of four separate programs: Systems Operations; Transmission Scheduling; Transmission Marketing; and Business Support.

- System Operations include technical operations, substation operations, control center support, and power system dispatching.
- The Scheduling program includes expenses for reservations, pre-scheduling, real-time scheduling, scheduling after-the-fact (ATF), and technical support.
- The Marketing program contains expenses for transmission sales, contract management, and marketing business strategy and assessment.
- Business support includes expenses for logistics services, aircraft services, and the Agency Services costs that provide support to the programs and organizations within Transmission Services and are direct-charged to Transmission.
- Although programs have increased in scope and responsibility, the internal operations costs have been held virtually flat for seven years. Increases reflect the IT, Supply Chain, Legal, Financial and other activities necessary to achieve the programs described above.

Changes in this area are strictly shifts from other areas. Increases of $3.9 million in FY 2010 and $4.0 million in FY 2011 are a result of costs related to Office of Workers' Compensation being moved from Transmission Agency Services to Transmission Operations. This increase is somewhat offset as a result of reorganizations that were not reflected in the initial IPR and are reflected in the final IPR. These reorganizations result in a slight shift in allocated costs of $1 million from Transmission internal costs to Power internal costs.

B. TRANSMISSION MAINTENANCE: SYSTEM MAINTENANCE AND ENVIRONMENTAL OPERATIONS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
125.7	125.8	0.1
FY 2011		
Initial IPR	**Final IPR**	**Change**
130.7	130.8	0.1

Maintenance consists of technical training, heavy mobile equipment maintenance, maintenance costs for system management, joint cost, power system control, system protection control, transmission line and substation.

The slight change in this area is due to reorganizations and is offset elsewhere in Transmission.

C. TRANSMISSION ENGINEERING

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
26.5	26.5	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
28.0	28.0	0

Engineering consists of: the research and development program; transmission system planning and analysis; regional association fees and costs associated with cancelled capital projects and inventory adjustments.

Comments Received on Transmission Expenses Generally:

- Tacoma Power expressed concern about the rate of increase in program spending. BPA should find ways to reduce them to more acceptable levels.
- ATNI suggested that BPA should provide more information on the cost components for how these cultural resources responsibilities (for Transmission Services) will be met for FY 2009 and to elaborate on the tribal consultation/coordination components related to these costs.

Response: As noted in workshops, Transmission operating costs are increasing due to a myriad of new requirements being placed on BPA including: mandatory reliability, environmental and tariff requirements; integration of wind resources; increased demand for capacity; the need to sustain aging transmission assets; and the need to renew investment in areas that have been historically under-invested. We believe that without these increases, BPA's ability to provide reliable transmission could seriously be jeopardized. Three EPIP's have been or are being implemented that are having significant positive impacts on our processes, addressing Performance Management, "Plan, Design, Build", and Supply Chain. However, the need to expand the system, address increased reliability standards and respond to the other FERC regulatory measures, such as Order 890, results in more costs, including not only capital investment and increased operations and maintenance costs, but additional support costs as well. The increased level of support needed from IT, Supply Chain, legal, and finance put additional pressure on our spending levels.

From 2009 to 2010 Transmission Maintenance increased by 13 percent. From 2010 to 2011 the rate of increase in these programs slowed to 4 percent. The largest FY 2009 to

FY 2010 increases in Transmission Maintenance are in the areas of Non-Electric Maintenance and Right-Of-Way (ROW) Maintenance.

Non-Electric Maintenance is increasing due to the implementation of the Facilities Asset Management Plan. The Facilities Asset Management Plan specifies a program of addressing the deferred maintenance on BPA's non-electric facilities identified during recent condition assessments. This has been an area that BPA has historically cut back spending but this work can no longer be deferred. The Facilities Asset Management Plan will bring BPA's facilities up to acceptable maintenance levels over the next 6 to 7 years with a focus in FY 2010 and 2011 on addressing critical deficiencies impacting personnel safety and transmission operations. Examples of critical life safety projects include the installation of lighted exit signs, emergency egress lighting, and panic hardware on doors. The program also places priority on addressing reliability issues on facility systems and equipment that are inadequate or have exhibited failures such as failing HVACs and roofs vital to the protection of the transmission equipment.

With the ROW Maintenance program, the primary driver for this sub-program is WECC/NERC compliance. The newly developed standards went into place in June 2007, making compliance with NERC's regulations for controlling vegetation along transmission line rights-of-way mandatory. BPA experienced a tree contact in 2007 and another in June of 2008. We provided our mitigation plans to WECC, noting that we were confident we could maintain compliance with the standards. As the largest transmission owner in the Pacific Northwest and a critical partner in the Western Interconnection, BPA understands the serious consequences vegetation threats pose. We take full responsibility for ensuring the reliability of our transmission grid, and we are taking unprecedented measures to identify and remove vegetation threats along our transmission lines to ensure we are in strict compliance with the vegetation standards systemwide. As a result, our expenses for right-of-way maintenance need to increase.

For Transmission Operations, the overall increase from FY 2009 to FY 2010 was 5 percent. From FY 2010 to FY 2011 the increase was less than inflation.

The drivers for the increases in Transmission Operations are:

- Mandatory reliability compliance; documentation and reporting have increased substantially.
- Increased workload to support wind integration.
- Increased demand for transmission capacity.
- Increased training needs due to constant influx of new equipment types, models, and technologies.

The increased funding will be used to:

- Provide tools to manage the system, e.g., automate remedial action scheme (RAS) arming, voltage control, and short-term wind forecasting.
- Increase management of conditional firm initiatives.
- Increase dynamic scheduling capability.

- Recognize opportunities to create more efficient inspection, documentation and switching processes and practices through internal and external benchmarking.
- Develop recruitment efforts that can supplement the success in the Apprenticeship Program.
- Digital communication to major federal projects and neighboring Balancing Authorities (BAs).

With regard to cultural resources, in some instances transmission maintenance activities may potentially impact cultural resources but are much less likely to do so than new projects where we are constructing on previously undisturbed ground. Most maintenance activities occur on previously disturbed ground where any cultural resources are likely to be known. However, if maintenance crews are performing work that may include previously undisturbed ground (e.g., creating a new section of access road, building a new culvert, etc.), then the Regional Natural Resource Specialist will contact the potentially affected Tribe(s) and/or contact BPA's Tribal Affairs to coordinate communication. Communication would occur similarly as described in the capital section on page 47.

Proposed spending has been adequate to cover all cultural resource preservation issues related to transmission activity to date.

Decision: Overall Transmission Operations and Maintenance expenses were reduced by \$1.0M per year for FY 2010 and 2011. This minor reduction was the result of efficiency related reorganizations and allocation of Agency Services costs. Additionally, there is a shift in OWCP costs from Transmission Agency Services to Transmission Operations.

D. AGENCY SERVICES/PENSION/POST-RETIREMENT BENEFITS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
78.2	74.4	(3.9)
FY 2011		
Initial IPR	**Final IPR**	**Change**
79.0	75.0	(4.0)

- Agency Services in Transmission is the equivalent cost category as internal operating costs in Power Services. These Agency Services costs provide support to the programs and organizations within Transmission Services and are either allocated or direct-charged to Transmission.
- Although programs have increased in scope and responsibility, the internal operations costs have been held virtually flat for seven years. Increases reflect the IT, Supply Chain, Legal, Financial and other activities necessary to achieve the programs described above.

- Decreases of $3.9 million in FY 2010 and $4.0 million in FY 2011 are as a result of costs related to Office of Workers' Compensation being moved from Transmission Agency Services to Transmission Operations.

Decision: No change to Agency Services Costs other than to reflect moving the OWCP costs from Transmission Agency Services to Transmission Operations.

E. TRANSMISSION CAPITAL

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
505.5	495.4	(10.1)
FY 2011		
Initial IPR	**Final IPR**	**Change**
568.9	567.1	(1.8)

Transmission capital is made up of four categories: Main Grid, Area and Customer Service, Upgrades and Additions, and Environment. Main Grid consists of major network reinforcements including McNary-John Day, Big Eddy and I-5 corridor. Area and Customer Service projects, and Upgrades and Additions assure that BPA meet's reliability standards and contractual obligations to its customers for serving load. The Capital Environment program addresses regulatory and liability issues at facilities likely to be adversely affected by water and environmental resources.

Comments Received:

- The Joint Public Power group appreciated the development of an asset management program to set priorities based on condition and risk.
- Tacoma Power commented that too much is planned in the early years of the construction program. Cost levelizing should be performed over the next few years. Given the shortage of line construction personnel, we question if the work can actually be accomplished or that BPA will pay premium prices for labor.
- The Joint Public Power group supports BPA's efforts to make investments needed for reliability. Investments should not be made unnecessarily. Given the large increases in the capital program, BPA should delay projects in future periods if it can be done without significant risk to reliability or load service.
- CRITFC does not support any reductions that reduce system reliability.
- PPC renews its request to meet with Transmission Services regarding its capital budget prior to that budget's inclusion in the OMB budget.

Response: As noted in IPR workshops, the transmission capital forecast represents increases that are necessary to meet several important pressures. The forecast is based on in-depth evaluation, assessment and prioritization as part of asset management planning.

Several comments indicate concerns that the capital program is front-loaded. The primary concern is the rate impact in FY 2010-2011; some utility customers would like it levelized to defer some costs out to FY 2012-2013. A secondary issue is Transmission's ability to staff the significant increase in work and the accompanying costs associated with contracting work out. There were concerns that the present labor shortage for line construction personnel will not only make it difficult to complete the capital program, but also the market premium for contract labor will push the capital program up.

Given the significant increase in the forecasted capital program and the labor shortage concerns raised in comment, it may be that more of a ramp-up period will be required. A larger lapse factor than proposed in the initial IPR forecast would recognize that possibility. The application of a 17-percent lapse factor, increased from the 15-percent lapse factor in the initial IPR, to the FY 2010-2011 period and reshaping the timing of the I-5 corridor project to reflect a more likely and achievable schedule has the affect of levelizing the program to some extent. It is expected that in 2012 and beyond there would be no lapse factor applied. In addition, the revenue requirement impacts of the capital program (depreciation, non-federal debt service, and net interest expense) in 2010 and 2011 are primarily from the 2008-2009 rate period. Likewise, the 2010 and 2011 capital program impacts the 2012 and 2013 capital program.

Transmission is currently looking at a number of ways to supplement and outsource needed human and construction resources. Major supply contracts for material and labor are being implemented. Coordination of projects with neighboring utilities will be required to maintain overall competitive pricing for the region.

Line construction personnel continue to be in high demand throughout the western U.S. BPA has joined a consortium of utilities in the West to examine best practices for construction employees, engineers, and materials. All three are in high demand and given our multi-year work plans we anticipate working through many resources to ramp-up accordingly. In addition, since we are planning our asset management programs for 3-5 years, we will be able to give contractors ample time to spread their workload to achieve the necessary upgrades.

Contract labor prices remain competitive in the Northwest. Since we currently have four major contract suppliers, we hope to maintain competitive pricing. Currently much of our work is done with in-house labor supplemented with crew members from contractors. Engineering, Procurement and Construction (EPC) or turnkey contracts will also be used to meet the high demand of construction labor. As we monitor all bid awards against in-house labor costs we will strive to contain our overall costs.

As mentioned in the June 30th technical workshop on Transmission's Asset Plan, Transmission is in catch-up mode, due to aging infrastructure and the capital program is filled with time critical investments, e.g. wood pole, spacers and breaker replacement programs, which make it very difficult to levelize the capital program.

Based on an assessment of FY 2009 new projects, one half of new starts are replacement projects needed to support the aging infrastructure. The other half of our new starts are nondiscretionary; nondiscretionary projects which include emergency replacements, mandatory replacements/upgrades/additions, and tariff generated projects.

These time critical projects are defined for FY 2009 capital as follows:

- Replace critical failed equipment or operational function. Funding needed to replace failed equipment and for operational functions that is critical to the reliable operation of the BPA transmission system. Examples include: failure of a power transformer; failure of a line protective relay; failure of station or communication batteries; major component failure of a Remedial Action Scheme; failure of a transmission line circuit; failure of a control system like SCADA.
- Mandatory replacements /upgrades/additions. Funding for projects to mitigate violations or resolve non-compliance or prevent non-compliance of federal law, including regulatory requirements or standards, such as FERC, NERC, environmental, and OSHA. The project submittal identifies the statute, requirement, or standard, including the specific section or clause,that applies and states why the project must start in the fiscal year in which it is reviewed.
- Tariff Generated Projects. Funding for projects in response to a Transmission Service Request, Generation Interconnection Request or Line/Load Interconnection Request made pursuant to BPA's OATT (Tariff).
    1) 100% Customer Financed/BPA owned Projects: Funding for all customer-financed projects with executed agreement. The project submittal identifies the specific customer agreement that applies and states why the project must start in the fiscal year in which it is reviewed.
    2) Network Open Season Projects: Funding for projects developed in response to the Network Open Season. The project submittal identifies the specific customer agreements that apply, the PTSA (contract) conditions have been satisfied and states why the project must start in the fiscal year in which it is reviewed.
    3) NT Projects: Projects required to accommodate current NT load and forecasted NT load growth. The project submittal identifies the specific customer agreement that applies and states why the project must start in the fiscal year in which it is reviewed.

In response to earlier customer requests to meet with Transmission Services regarding its proposed capital spending prior to the development of the Federal budget, the Agency held the Capital Planning Review as an interim step aimed at giving the stakeholders a consolidated view of and input into BPA's capital investments. To accomplish this, BPA combined the capital review processes for the Power Services and Transmission Services. Through the Capital Planning Review, BPA involved stakeholders in capital management decisions, giving stakeholders the opportunity to influence how the agency makes capital investments that affect future power and transmission rates. Proposed spending estimates were presented for a five-year period (in response to customer comments that a longer horizon is necessary for capital). All capital projects were addressed including projects that have not yet been approved (new starts) and capital investments that are expected to be placed into service during the upcoming rate period.

As previously noted, BPA held extensive discussions with customers and other stakeholders to develop approaches to provide regional transparency and accountability for BPA cost management efforts. As a result, BPA initiated a new process this year for regional stakeholders to engage BPA on planned program spending levels that will form the basis for input to both Power Services and Transmission Services rate setting. The overall process is the Integrated Business Review (IBR) which consists of two major sub-processes: 1) the IPR and 2) the Quarterly Business Review (QBR).

For Cultural Resources, once a transmission project is in the final planning stages and we are ready to begin the environmental work, BPA sends written notification to each of the potentially affected tribes. We typically follow up with phone calls to the Cultural Resources Manager, Natural Resources Manager, and THPO. In the notification we offer formal consultation and by phone call, offer to meet at the staff level to discuss the proposed project and any issues they might have. If more than one tribe may be impacted, we typically request that one tribe represent the affected tribes as the lead tribe. Ongoing discussions are conducted with the lead Tribe which has the responsibility to inform the other tribes of any issues. The Project Manager, Environmental Lead, Tribal Account Executive (and others as appropriate) will meet periodically at the staff level to keep tribal staff informed (we send them letters as well, to keep them informed) and offer to meet with any tribal council members, as tribal staff deem appropriate.

During the estimating phase, BPA's Tribal Affairs provides an estimate of costs, typically for tribal monitoring during construction, which is included in the approved capital project proposal. The lead Tribe may share with us any cultural resource issues around the proposed project route and we try to make adjustments to avoid cultural resource sites. At times, we may uncover cultural resources that neither BPA nor a tribe was aware of (e.g., Decatur Island burial site), at which point work is stopped. BPA must then assess what is appropriate and required to preserve the resource. Any needed funding amounts goes back through the capital budget group, but in every case money is added to mitigate for cultural resource preservation (e.g., in the case of Decatur Island, over $1.5 million was added to the capital project proposal). BPA's relationship with tribes in the Pacific Northwest is important and is conducted on a government-to-government level, which ensures that matters such as cultural resource preservation is respected. Project Managers, Environmental Leads and Tribal Affairs work proactively with all potentially affected tribes on any proposed Transmission project.

Decision: BPA believes that the forecasts for capital investment do not include any "unnecessary" work, and that the schedule is based on sound assessment and prioritization of the work that is necessary. However, as suggested in comments, BPA has reviewed the timelines for its capital Transmission programs. BPA has determined that the timing of the I-5 Corridor project as proposed in the initial IPR is likely too optimistic and that an adjustment to the schedule is appropriate. For that reason, the large investment planned for FY 2011 will be moved to FY 2012. Additionally, in recognition of the difficulty in implementing such a large increase in the capital program, as pointed out in comments, the 15-percent lapse factor applied to all Transmission capital in the initial IPR forecasts has been increased to 17 percent for all Transmission capital.

COST DECISIONS TO BE MADE AS PART OF THE RATE CASE

The following section provides information on areas for which the costs will be determined in the FY 2010-2011 rate proposal. They have been included in the IPR to provide an opportunity for participants to understand the basis for these costs.

F. TRANSMISSION ACQUISITION AND ANCILLARY SERVICES

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
18.4	18.4*	0

FY 2011		
Initial IPR	**Final IPR**	**Change**
18.4	18.4*	0

Includes 3rd party only

* The actual amount will be determined in the Final Rate Proposal.

G. TOTAL NET INTEREST, AMORTIZATION/DEPRECIATION AND NON-FEDERAL DEBT SERVICE

$ millions

Net Interest

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Transmission	150.6	151.1*	
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Transmission	168.7	168.6*	

Amortization/Depreciation

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Transmission	200.8	200.8*	0
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Transmission	211.5	211.5*	0

Non-Federal Debt Service

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Transmission	5.9	5.9*	0
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Transmission	4.7	4.7*	0

*These are a very preliminary estimates provided for information only. The final amounts will be determined in the rate case and could be considerably different due to such things as updated actual 2008 data.

Decision: Changes since the initial IPR numbers reflect the decisions described above related to the change in the planned schedule for construction of the I-5 corridor project, and the increased lapse factor applied to Transmission capital. The changes in capital result in a small reduction in interest which is offset by a reduction in AFUDC. Other changes that affect the current estimates are revised estimates of FY 2008 investments and revised reserves estimates resulting in different interest earnings assumptions. The final levels of these forecasts will be determined in the final rate proposal.

H. DEBT MANAGEMENT

Debt management issues are not decided in the IPR. Decisions and assumptions on debt management are rate case issues and will be discussed in that forum. However, BPA believes it is important to show in the IPR the impact of past and future debt management decisions since these impact power rates. This IPR final report is intended to portray BPA's current thinking on these issues; however it does not make any decisions associated with debt management issues.

BPA's debt management process is largely driven by actual and forecasts of future capital investments in the FCRPS. Management of this program entails comprehensive review of options for reducing debt service costs based on assumptions about capital spending, interest rate yield curves, and retaining access to capital. However, the primary driver of costs in this area is capital spending levels. The IPR includes discussion on these items because it is important for participants to understand the implications of past debt management decisions and proposed capital spending levels. That said, review during the IPR has led to some changes, the impacts of which are estimated here. The levels for these cost categories may be different in the Final Rate Proposal.

Section 4
AGENCY SERVICES

AGENCY SERVICES

Agency Services include direct program support costs as well as general and administrative costs. These activities are integral to and in support of the work described in the Power and Transmission sections. The costs are distributed to and embedded in the Power and Transmission costs.

Some of the larger programs and their drivers are:

- Supply Chain's spending is driven by the programmatic levels of Transmission O&M and construction, Fish and Wildlife, Energy Efficiency, Technology Innovation, and Workplace Services (non-electric facilities build, repair and maintenance), and the agency's supplemental labor force and contract services requirements.
- General Counsel supports BPA programs through legal advice and representation.
- Internal Audit supports governance and serves BPA managers through audits, reviews, analyses, and other services.
- ColumbiaGrid was created to promote regional transmission planning in response to Federal Energy Regulatory Commission (FERC) Order 890.
- Finance provides general accounting and financial reporting, cash management, Treasury and third- party financing, accounts payable and receivable services, rate case revenue requirement development and support, financial planning, Agency budget development and support and Agency cost management support.
- Information Technology proposed spending reflects implementation of system enhancements to meet emerging business requirements and to support efficiencies in organizations across the Agency; implementing changes due to mandatory regulation such as Federal Information Security Management Act and OMB Circular A123; and maintaining the reliability of hardware through maintenance and refresh.
- The Security and Emergency Response program is designed to ensure the protection of BPA's workforce, physical and electronic assets and support the reliability of BPA's operations and services to the Pacific Northwest.
- HCM's proposed spending reflects both the significant EPIP savings and the resources to deliver the full range of HCM activities including labor relations, employee relations, hiring and recruiting, training, benefits, personnel policy development and management, etc.
- Workplace Services consists of facilities (HQ and Ross O&M and non-electric facilities including field office facilities), leases, space management, office services, printing and mail services.

Comments Received:

- Tacoma Power commented that BPA should not initiate any R&D before customers can review the projects. Customers should be involved in the Technology Confirmation/Innovation Council and have access to reports.

- Tacoma Power also noted that total internal agency costs are increasing by 39.3%. BPA should review these costs and find ways to reduce them to more acceptable levels (inflation or less).
- The Joint Public Power group commented that [Agency Services] spending increases should be held to the rate of inflation.

Response: Regarding Agency Services costs in general: Many of the Efficiency Project Improvement Program (EPIP) savings have been achieved in Agency Services, including Human Capital Management, Information Technology, and Public Affairs. Several of the EPIPs also recommended process improvements that resulted in the consolidation of many functions (from the Business Units to Agency Services), including Supply Chain, Metering and Billing, Load Forecasting, and Contract Administration. Finance also experienced a consolidation of business and management support from Power and Transmission to a central group. These consolidations have lead to a change to Agency Services costs, making them appear higher than if consolidation had not occurred.

Power and Transmission programs and projects are significant drivers of Agency Services costs. Growth in existing programs and/or new initiatives has resulted in increased demand for Agency Services supporting activities. Some of the most significant power and transmission program changes and their impacts on Agency Services are:

- Supply Chain's spending is driven by the programmatic levels of Transmission O&M and construction, Fish and Wildlife, Energy Efficiency, Technology Innovation, Workplace Services (non-electric facilities build, repair and maintenance), and the agency's supplemental labor force and contract services requirements. The FY 2010 and FY 2011 proposed spending estimates have fully incorporated the efficiency savings from the Supply Chain and Plan-Design-Build EPIPs resulting from the Work Planning and Scheduling System and the "80 percent stable work plan" for transmission. Other pressures are the redesign of inventory and purchasing processes, internal controls, and performance to ensure compliance with Agency Master Lease initiative.
- Workplace Services consists of facilities (HQ and Ross O&M and asset management), leases, space management, office services, printing, and mail services. The overall trend for Workplace Services' base program is to stay level with the exception of the new facilities asset management program. Condition assessments conducted as part of Facilities Asset Management (FAM) plan determine current risk exposure. Increased proposed funding is included to address backlog of facilities-related deferred maintenance.
- Information Technology spending was reduced before all of the efficiencies needed to support the reductions were completed; realization of the efficiencies requires expenditure of expense dollars. Pressures include:
  - Capital projects implement business units Enterprise Process Improvement Program initiatives which provide business units with savings while IT funds ongoing expense support tail. Expense support tails need to be funded as capital projects are approved. Provide automated solutions to support wind integration

- Providing automated solutions to support Regional Dialogue.
- Responding to emerging cyber threats (e.g. spam filters, whole disk encryption to protect Personal Identifying Information)
- Introducing and leveraging emerging technologies (e.g. hierarchical storage, virtualization/multi-cores, IPv6)

- General Counsel's forecast is driven by increased need for legal services in transmission due to increased investments and Transmission Service Agreements, resumptions of the Residential Exchange Program (REP) with attendant legal review, increases in Fish and Wildlife programs, new reliability standards, and compliance requirements.
- Customer Support Services program levels reflect new workload associated with implementation of increasingly complex Regional Dialogue contracts, the necessity of administering existing power subscription agreements in parallel with preparing for implementing Regional Dialogue contracts, and increased BPA data and forecasting requirements for loads, resources and REP, all requiring enhancements to billing, contracts and load forecasting systems. The impacts of specific initiatives such as WREGIS, FERC Order 890 implementation, Resource Program, etc., are not specifically known, but are expected to be addressed within the forecasted levels of FTE and budgets.
- Finance's expense level as increased primarily due to the consolidation of staff from Power and Transmission. FY 2010-2011 cost increases are slightly higher than inflation to allow for increased financing and accounting support of growing Power and Transmission activities. Finance provides general accounting and financial reporting, cash management, Treasury and third- party financing, accounts payable and receivable services, rate case revenue requirement development and support, financial planning, Agency budget development and support and Agency cost management support.
- Growth in the Security and Emergency Response program is limited to capital spending as security has increased at Headquarters and field sites. This program is designed to ensure the protection of BPA's workforce, physical and electronic assets and support the reliability of BPA's operations and services to the Pacific Northwest.

No comments were received in the IPR process concerning the Northwest Power and Conservation Council proposed spending agreement. The Council's proposal for FY 2010 is the same, $9.683 million, as presented in the IPR workshop. The Council's proposal for FY2011 is $9.934 million, which is $73 thousand higher than the IPR workshop. The Council received no comment on the proposed spending agreement during the Council's public process.

The proposed Agency Services program levels are essential to the accomplishment of business unit and agency initiatives.

Regarding BPA's Technology Innovation program, the Research and Development (R&D) program is driven by a strategic need to focus on solutions to technology related business challenges. Our research agenda is described in a set of publicly available technology roadmaps easily accessed from this link on BPA's home page (http://www.bpa.gov/corporate/business/innovation/). As they become available, research results are also posted to that web page.

Customer review of our research agenda, as expressed in our technology roadmaps, is welcome at any time. Roadmaps are updated periodically to address changes in the current state of technology and changes in BPA's business challenges. Comments on our roadmaps should be addressed to BPA Technology Innovation Office - DE-3, PO Box 3621, Portland Oregon 97208-3621.

We are considering a means for customer involvement in our Technology Confirmation / Innovation Council. To that end we have met with the executive leadership of several utilities including Tacoma Power. To date, no utility has expressed an interest in helping guide BPA's R&D agenda. We will continue to explore means of more fully engaging customers. Terry Oliver, BPA's Chief Technology Innovation Officer, is available to brief any party on our R&D effort. Please contact your BPA Account Executive.

Decision: No change to Agency Services total program levels as presented in the IPR workshops and as reflected in the Council's proposed spending agreement.

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APPENDIX B

REPAYMENT PROGRAM TABLES

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DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table 10 shows the amortization results from the Generation repayment studies for FY 2010-2011, summarized by bonds, appropriations, and irrigation due and discretionary, by year.

Tables 11A-F and 12A-F show the results from the Generation repayment studies for FY 2010 and 2011, respectively, using revenues from current rates. Table 14 provides the application of amortization through the repayment period for generation based upon the revenues forecast using current rates.

Tables 11A and 12A display the repayment program results for generation for FY 2010 and 2011, respectively. The first column shows the applicable fiscal year. The second column shows the total investment costs of the generating projects through the cost evaluation period. *See* Documentation, WP-10-E-BPA-02A, Chapter 4. In the third column, forecasted replacements required to maintain the system are displayed through the repayment period. *See* Documentation, WP-10-E-BPA-02A, Chapter 10. The fourth column shows the cumulative dollar amount of the generation investment placed in service. This is comprised of historical plant-in-service, planned replacements and additions to plant through the cost evaluation period, and replacements from the end of the cost evaluation period to the end of the repayment study period. For these studies, all additional plant is assumed to be financed by either appropriations or bonds.

The next two columns show scheduled amortization payments for each year of the repayment period (due and discretionary). Discretionary amortization shows generation amortization payments made before the due dates of each particular obligation.

Unamortized investments, shown in column 7, are determined by taking the previous year's unamortized amount, adding any replacements, and subtracting amortization. Column 8 shows the unamortized obligations as determined by a term schedule (if all obligations were paid at maturity and never early). It should be noted that unamortized obligations are always less than the term schedule, indicating that planned repayments are in excess of repayment obligations, thereby satisfying repayment requirements. The total of Unamortized Investment need not be zero at the end of the repayment period because of the replacements occurring subsequent to the cost evaluation period.

Columns 9, 10, and 11 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 and 12B display planned principal payments by fiscal year for Federal generation obligations. Shown on these tables are the principal payments associated with the appropriations of the COE and Reclamation, and BPA bonds.

Tables 11C and 12C 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. These capitalized contractual obligations are 100 percent generation-related.

Tables 11D and 12D show the planned interest payments by fiscal year for Federal generation obligations. Shown on these tables are the interest payments associated with the appropriations of the COE and Reclamation, and BPA bonds.

Tables 11E and 12E show the component of the capitalized contractual obligations associated with payment of interest expense. Included is the stream of payments associated with a long-term, relatively fixed, energy resource acquisition contract that will not be capitalized. The capitalized contractual obligations are 100 percent generation-related.

Tables 11F and 12F show a summary of all Federal and capitalized contract obligations, principal, and interest payments.

Table 13 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
Amortization - Generation
FY 2010-2011
($000s)

10A: Maturing/Due

Bonds		
	2010	68
	2011	
	Total	68
Appropriations		
	2010	0
	2011	0
	Total	0
Irrigation Assistance		
	2010	0
	2011	0
	Total	0
	TOTAL	**68**

10B: Scheduled But Not Yet Due

Bonds		
	2010	0
	2011	0
	Total	0
Appropriations		
	2010	267,196
	2011	161,888
	Total	429,084
	TOTAL	**429,084**

10C: Total by Year

Bonds		
	2010	68
	2011	0
	Total	68
Appropriations		
	2010	267,196
	2011	161,888
	Total	429,084
Irrigation Assistance		
	2010	0
	2011	0
	Total	0
Total		
	2010	267,264
	2011	161,888
	TOTAL	**429,152**

Table 11A: Generation Investments Placed in Service FY 2010
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1		Investment Placed in Service							Irrigation Assistance		
2	Fiscal Year	Initial Project	Replacements	Cumulative Amount in Service	Due Amortization	Discretionary Amortization	UnAmortized Investment	Term Investment Schedule	Cumulative Amount in Serivce	Amortization	Unamortized Amount
3	2009	333,152	-	4,470,376	92,990	10,075	4,367,311	5,417,603	683,690	7,274	676,416
4	2010	362,021	126,180	4,958,577	68	267,196	4,588,248	5,656,219	690,632	-	683,358
5	2011	-	117,932	5,076,509	-	161,888	4,544,292	5,584,034	697,198	-	689,924
6	2012	-	110,125	5,186,634	92,800	2,444	4,559,174	5,423,128	700,674	1,206	692,194
7	2013	-	102,832	5,289,466	70,000	18,067	4,573,939	5,315,960	720,467	60,027	651,960
8	2014	-	103,207	5,392,673	65,850	34,025	4,577,271	5,328,443	757,997	53,500	635,990
9	2015	-	103,601	5,496,274	32,300	24,991	4,623,581	5,279,744	763,104	125,899	515,198
10	2016	-	103,993	5,600,267	-	-	4,727,574	5,381,033	768,498	41,452	479,140
11	2017	-	104,447	5,704,714	-	-	4,832,021	5,419,354	803,751	1	514,392
12	2018	-	104,961	5,809,675	-	137,300	4,799,683	5,479,110	854,938	27,989	537,590
13	2019	-	105,532	5,915,207	40,000	572,216	4,292,998	5,459,870	865,840	58,168	490,324
14	2020	-	106,154	6,021,361	30,000	556,369	3,812,783	5,457,195	887,098	24,943	486,639
15	2021	-	106,827	6,128,188	-	625,524	3,294,087	5,480,174	926,305	12,354	513,492
16	2022	-	107,545	6,235,733	-	667,593	2,734,039	5,519,990	965,354	14,585	537,956
17	2023	-	95,731	6,331,464	-	706,061	2,123,709	5,442,708	994,434	13,252	553,784
18	2024	-	85,358	6,416,822	50,000	648,436	1,510,630	5,470,798	1,036,240	15,414	580,176
19	2025	-	76,207	6,493,029	70,000	538,606	978,232	5,237,515	1,056,277	13,900	586,313
20	2026	-	68,142	6,561,171	0	634,190	412,184	5,069,470	1,089,505	21,154	598,387
21	2027	-	61,037	6,622,208	-	73,540	399,681	5,019,396	1,121,733	192,572	438,043
22	2028	-	54,710	6,676,918	-	54,710	399,681	4,857,906	1,155,119	-	471,429
23	2029	-	49,119	6,726,037	-	49,119	399,681	4,649,604	1,199,916	-	516,226
24	2030	-	44,228	6,770,265	-	44,228	399,681	4,690,718	1,229,879	-	546,189
25	2031	-	39,875	6,810,140	30,000	39,875	369,681	4,688,241	1,259,842	-	576,152
26	2032	-	36,033	6,846,173	-	36,033	369,681	4,517,761	1,304,639	-	620,949
27	2033	-	51,481	6,897,654	20,000	51,481	349,681	4,269,913	1,345,063	-	661,373
28	2034	-	51,949	6,949,603	-	51,949	349,681	4,321,862	1,385,487	-	701,797
29	2035	-	52,461	7,002,064	-	52,461	349,681	4,326,109	1,414,694	-	731,004
30	2036	-	52,957	7,055,021	9,681	52,957	340,000	4,378,802	1,443,243	-	759,553
31	2037	-	53,494	7,108,515	-	53,494	340,000	4,359,760	1,471,951	-	788,261
32	2038	-	54,070	7,162,585	-	54,070	340,000	4,394,982	1,501,261	-	817,571
33	2039	-	54,684	7,217,269	45,000	54,684	295,000	4,449,666	1,530,572	-	846,882
34	2040	-	55,280	7,272,549	-	55,280	295,000	4,502,189	1,564,407	-	880,717
35	2041	-	55,911	7,328,460	30,000	55,911	265,000	4,549,349	1,598,243	-	914,553
36	2042	-	56,577	7,385,037	105,000	56,577	160,000	4,605,052	1,632,937	-	949,247
37	2043	-	53,302	7,438,339	50,000	53,302	110,000	4,500,876	1,667,632	-	983,942
38	2044	-	50,220	7,488,559	85,000	50,220	25,000	4,467,809	1,700,573	-	1,016,883
39	2045	-	47,374	7,535,933	25,000	47,374	(0)	4,412,366	1,733,514	-	1,049,824
40	2046	-	44,703	7,580,636	0	44,703	(0)	4,428,221	1,766,613	-	1,082,923
41	2047	-	42,201	7,622,837	(0)	42,201	(0)	4,401,106	1,806,338	-	1,122,648
42	2048	-	39,862	7,662,699	-	39,862	(0)	4,440,968	1,846,221	-	1,162,531
43	2049	-	35,966	7,698,665	0	35,966	(0)	4,432,934	1,886,104	-	1,202,414
44	2050	-	32,499	7,731,164	0	32,499	(0)	4,378,826	1,909,360	-	1,225,670
45	2051	-	29,444	7,760,608	(0)	29,444	(0)	4,299,335	1,932,775	-	1,249,085
46	2052	-	26,740	7,787,348	(0)	26,740	(0)	4,312,148	1,957,121	-	1,273,431
47	2053	-	41,875	7,829,223	(0)	41,875	(0)	4,278,437	1,988,437	-	1,304,747

Table 11A: Generation Investments Placed in Service FY 2010
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1		Investment Placed in Service							Irrigation Assistance		
2	Fiscal Year	Initial Project	Replacements	Cumulative Amount in Service	Due Amortization	Discretionary Amortization	UnAmortized Investment	Term Investment Schedule	Cumulative Amount in Serivce	Amortization	Unamortized Amount
48	2054	-	42,436	7,871,659	0	42,436	(0)	4,068,374	2,019,753	-	1,336,063
49	2055	-	43,028	7,914,687	(0)	43,028	(0)	3,654,696	2,051,069	-	1,367,379
50	2056	-	43,649	7,958,336	(0)	43,649	(0)	3,195,803	2,075,263	-	1,391,573
51	2057	-	44,255	8,002,591	(0)	44,255	(0)	3,072,503	2,075,263	-	1,391,573
52	2058	-	44,890	8,047,481	(0)	44,890	(0)	2,956,015	2,075,263	-	1,391,573
53	2059	-	45,553	8,093,034	-	45,553	(0)	2,898,361	2,075,263	-	1,391,573
54	2060	-	-	8,093,034	-	-	(0)	2,596,760	2,075,263	-	1,391,573
55	**Total**	**$695,173**	**$3,260,637**	-	**$943,689**	**$7,149,345**	-		-	**$683,690**	-

Table 11B: Generation Federal Principal Payments FY 2010
($000s)

	A	B	C	D	E	F	G	H	I
1	**Fiscal Year**		**BPA Bonds**		**Corps of Engineers Appropriations**		**Bureau of Reclamation Appropriations**		**Irrigation Amortization**
2	2009		92,990		10,075		-		7,274
3	2010		68		266,346		850		-
4	2011		-		161,888		-		-
5	2012		92,800		2,444		-		1,206
6	2013		70,000		18,067		-		60,027
7	2014		65,850		26,280		7,745		53,500
8	2015		32,300		-		24,991		125,899
9	2016		-		-		-		41,452
10	2017		-		-		-		1
11	2018		-		125,838		11,462		27,989
12	2019		40,000		362,458		209,758		58,168
13	2020		30,000		365,403		190,966		24,943
14	2021		152,960		392,412		80,151		12,354
15	2022		18,761		648,832		-		14,585
16	2023		-		706,061		-		13,252
17	2024		50,000		567,450		80,986		15,414
18	2025		215,952		376,693		15,961		13,900
19	2026		-		634,113		76		21,154
20	2027		-		73,540		-		192,572
21	2028		-		54,710		-		-
22	2029		-		49,119		(0)		-
23	2030		-		44,228		-		-
24	2031		30,000		39,875		-		-
25	2032		-		36,033		-		-
26	2033		20,000		51,481		-		-
27	2034		-		51,949		-		-
28	2035		-		52,461		-		-
29	2036		9,681		52,957		-		-
30	2037		-		53,494		-		-
31	2038		-		54,070		-		-
32	2039		45,000		54,684		-		-
33	2040		-		55,280		-		-
34	2041		30,000		55,911		-		-
35	2042		105,000		56,577		-		-
36	2043		50,000		53,302		-		-
37	2044		85,000		50,220		-		-
38	2045		25,000		47,374		0		-
39	2046		-		44,703		0		-
40	2047		-		42,201		0		-
41	2048		-		39,862		-		-
42	2049		-		35,966		-		-
43	2050		-		32,499		-		-
44	2051		-		29,444		(0)		-
45	2052		-		26,740		-		-
46	2053		-		41,875		-		-
47	2054		-		42,436		-		-
48	2055		-		43,028		0		-
49	2056		-		43,649		-		-
50	2057		-		44,255		0		-
51	2058		-		44,890		(0)		-
52	2059		-		45,553		-		-
53	2060		-		(0)		-		-
54	**Total**		**$1,261,362**		**$6,208,726**		**$622,946**		**$683,690**

Table 11C: Generation Component of Capitalized Contract Principal Payments FY 2010
($000s)

	A	B	C	D	E	F	G	H
1	**Fiscal Year**		**EN**			**Other**		**Total**
2	2009		265,499			10,161		275,660
3	2010		275,047			10,647		285,694
4	2011		310,343			11,148		321,492
5	2012		411,702			11,699		423,401
6	2013		370,869			12,277		383,146
7	2014		389,465			12,895		402,360
8	2015		399,071			8,818		407,888
9	2016		553,635			8,943		562,579
10	2017		618,597			9,403		628,000
11	2018		488,765			9,873		498,638
12	2019		31,020			10,367		41,387
13	2020		125,686			10,886		136,572
14	2021		132,173			11,435		143,608
15	2022		138,924			12,014		150,938
16	2023		146,024			13,028		159,052
17	2024		121,919			13,683		135,601
18	2025		33,483			353		33,835
19	2026		35,777			0		35,777
20	2027		38,228			0		38,228
21	2028		40,846			0		40,846
22	2029		43,644			0		43,644
23	2030		46,634			0		46,634
24	2031		49,828			0		49,828
25	2032		53,242			0		53,242
26	2033		56,889			0		56,889
27	2034		60,785			0		60,785
28	2035		64,949			0		64,949
29	2036		69,398			0		69,398
30	2037		74,152			0		74,152
31	2038		79,231			0		79,231
32	2039		84,659			0		84,659
33	2040		90,458			0		90,458
34	2041		96,654			0		96,654
35	2042		103,275			0		103,275
36	2043		110,349			0		110,349
37	2044		117,908			0		117,908
38	2045		125,984			0		125,984
39	2046		134,615			0		134,615
40	2047		143,836			0		143,836
41	2048		153,689			0		153,689
42	2049		164,216			0		164,216
43	2050		175,465			0		175,465
44	2051		187,485			0		187,485
45	2052		200,327			0		200,327
46	2053		214,049			0		214,049
47	2054		228,712			0		228,712
48	2055		244,379			0		244,379
49	2056		261,118			0		261,118
50	2057		279,005			0		279,005

Table 11C: Generation Component of Capitalized Contract Principal Payments FY 2010
($000s)

	A	B	C	D	E	F	G	H
1	**Fiscal Year**		**EN**			**Other**		**Total**
51	2058		298,117			0		298,117
52	2059		318,538			0		318,538
53	2060		250,970			0		250,970
54	**Total**		**$9,509,627**			**$177,628**		**$9,687,254**

Table 11D: Generation Federal Interest Payments FY 2010
($000s)

	A	B	C	D	E	F	G
1	**Fiscal Year**		**BPA Bonds (1)**		**Corps of Engineers Appropriations**		**Bureau of Reclamation Appropriations**
2	2009		34,814		174,856		43,187
3	2010		38,174		178,944		43,187
4	2011		49,835		172,648		43,126
5	2012		55,415		168,761		43,126
6	2013		53,333		175,788		43,126
7	2014		49,102		181,220		43,126
8	2015		45,932		186,088		42,571
9	2016		47,518		192,864		40,782
10	2017		48,318		199,665		40,782
11	2018		44,342		206,496		40,782
12	2019		32,741		204,363		39,962
13	2020		32,764		185,349		24,964
14	2021		39,030		166,165		11,310
15	2022		21,536		145,094		5,579
16	2023		19,394		109,694		5,579
17	2024		20,443		69,778		5,579
18	2025		25,834		41,418		821
19	2026		9,473		25,982		3
20	2027		9,477		547		-
21	2028		9,481		-		-
22	2029		9,485		-		-
23	2030		9,490		-		-
24	2031		9,494		-		-
25	2032		7,760		-		-
26	2033		7,766		-		-
27	2034		6,456		-		-
28	2035		6,463		-		-
29	2036		6,470		-		-
30	2037		5,892		-		-
31	2038		5,900		-		-
32	2039		5,908		-		-
33	2040		3,403		-		-
34	2041		3,413		-		-
35	2042		1,347		-		-
36	2043		(5,895)		-		-
37	2044		(8,903)		-		-
38	2045		(14,501)		-		-
39	2046		(16,187)		-		-
40	2047		(16,173)		-		-
41	2048		(16,158)		-		-
42	2049		(16,142)		-		-
43	2050		(16,125)		-		-
44	2051		(16,107)		-		-
45	2052		(16,087)		-		-
46	2053		(16,067)		-		-
47	2054		(16,044)		-		-
48	2055		(16,021)		-		-
49	2056		(15,995)		-		-
50	2057		(15,968)		-		-
51	2058		(15,939)		-		-
52	2059		(15,908)		-		-
53	2060		(17,989)		-		-
54	**Total**		**$503,992**		**$2,785,718**		**$517,593**

Table 11E: Generation Component of Capitalized Contract Interest Payments
FY 2010
($000s)

	A	B	C	D	E	F	G
1	**Fiscal Year**		**EN**		**Other**		**Total**
2	2009		279,794		8,765		288,559
3	2010		262,160		8,198		270,358
4	2011		246,592		7,534		254,126
5	2012		233,262		6,977		240,239
6	2013		217,509		6,378		223,887
7	2014		192,429		5,750		198,179
8	2015		156,582		5,209		161,791
9	2016		137,501		4,763		142,263
10	2017		106,375		4,301		110,676
11	2018		68,071		3,816		71,887
12	2019		35,279		3,307		38,586
13	2020		33,675		2,772		36,447
14	2021		27,194		2,211		29,405
15	2022		20,435		1,621		22,055
16	2023		13,331		991		14,322
17	2024		81,768		341		82,108
18	2025		303,250		9		303,259
19	2026		301,104		0		301,104
20	2027		298,810		0		298,810
21	2028		296,360		0		296,360
22	2029		293,742		0		293,742
23	2030		290,944		0		290,944
24	2031		287,955		0		287,955
25	2032		284,761		0		284,761
26	2033		281,348		0		281,348
27	2034		277,702		0		277,702
28	2035		273,805		0		273,805
29	2036		269,642		0		269,642
30	2037		265,194		0		265,194
31	2038		260,441		0		260,441
32	2039		255,362		0		255,362
33	2040		249,935		0		249,935
34	2041		244,137		0		244,137
35	2042		237,941		0		237,941
36	2043		231,321		0		231,321
37	2044		224,248		0		224,248
38	2045		216,690		0		216,690
39	2046		208,615		0		208,615
40	2047		199,986		0		199,986
41	2048		190,766		0		190,766
42	2049		180,915		0		180,915
43	2050		170,388		0		170,388
44	2051		159,141		0		159,141
45	2052		147,123		0		147,123
46	2053		134,282		0		134,282
47	2054		120,562		0		120,562
48	2055		105,901		0		105,901
49	2056		90,237		0		90,237
50	2057		73,499		0		73,499
51	2058		55,615		0		55,615
52	2059		36,505		0		36,505
53	2060		16,087		0		16,087
54	**Total**		**$9,646,271**		**$72,943**		**$9,719,214**

Table 11F: Generation
Summary of Payments
FY 2010
($000s)

	A	B	C	D	E	F	G
1		Principal			Interest		
2	Fiscal Year	Generation Payment	Capitalized Contracts Payment	Total Principal Payment	Generation Payment	Capitalized Contracts Payment	Total Interest Payment
3	2009	110,339	275,660	385,999	252,858	288,559	288,559
4	2010	267,264	285,694	552,958	260,305	270,358	530,663
5	2011	161,888	321,492	483,380	265,609	254,126	519,735
6	2012	96,450	423,401	519,851	267,302	240,239	507,541
7	2013	148,094	383,146	531,239	272,247	223,887	496,135
8	2014	153,375	402,360	555,735	273,448	198,179	471,627
9	2015	183,190	407,888	591,078	274,592	161,791	436,383
10	2016	41,452	562,579	604,030	281,164	142,263	423,427
11	2017	1	628,000	628,001	288,765	110,676	399,442
12	2018	165,289	498,638	663,927	291,620	71,887	363,507
13	2019	670,384	41,387	711,771	277,065	38,586	315,650
14	2020	611,312	136,572	747,884	243,076	36,447	279,524
15	2021	637,878	143,608	781,485	216,504	29,405	245,909
16	2022	682,178	150,938	833,116	172,209	22,055	194,264
17	2023	719,313	159,052	878,365	134,667	14,322	148,989
18	2024	713,850	135,601	849,451	95,800	82,108	177,908
19	2025	622,506	33,835	656,341	68,073	303,259	371,332
20	2026	655,344	35,777	691,120	35,458	301,104	336,562
21	2027	266,112	38,228	304,340	10,024	298,810	308,834
22	2028	54,710	40,846	95,556	9,481	296,360	305,841
23	2029	49,119	43,644	92,763	9,485	293,742	303,227
24	2030	44,228	46,634	90,862	9,490	290,944	300,434
25	2031	69,875	49,828	119,703	9,494	287,955	297,449
26	2032	36,033	53,242	89,275	7,760	284,761	292,521
27	2033	71,481	56,889	128,370	7,766	281,348	289,114
28	2034	51,949	60,785	112,734	6,456	277,702	284,158
29	2035	52,461	64,949	117,410	6,463	273,805	280,268
30	2036	62,638	69,398	132,036	6,470	269,642	276,112
31	2037	53,494	74,152	127,646	5,892	265,194	271,086
32	2038	54,070	79,231	133,301	5,900	260,441	266,340
33	2039	99,684	84,659	184,343	5,908	255,362	261,270
34	2040	55,280	90,458	145,738	3,403	249,935	253,339
35	2041	85,911	96,654	182,565	3,413	244,137	247,550
36	2042	161,577	103,275	264,852	1,347	237,941	239,288
37	2043	103,302	110,349	213,651	-5,895	231,321	225,426
38	2044	135,220	117,908	253,128	-8,903	224,248	215,345
39	2045	72,374	125,984	198,358	-14,501	216,690	202,190
40	2046	44,703	134,615	179,318	-16,187	208,615	192,427
41	2047	42,201	143,836	186,037	-16,173	199,986	183,813
42	2048	39,862	153,689	193,551	-16,158	190,766	174,608
43	2049	35,966	164,216	200,182	-16,142	180,915	164,772
44	2050	32,499	175,465	207,964	-16,125	170,388	154,263
45	2051	29,444	187,485	216,928	-16,107	159,141	143,034
46	2052	26,740	200,327	227,067	-16,087	147,123	131,036
47	2053	41,875	214,049	255,924	-16,067	134,282	118,216
48	2054	42,436	228,712	271,148	-16,044	120,562	104,517
49	2055	43,028	244,379	287,406	-16,021	105,901	89,881
50	2056	43,649	261,118	304,767	-15,995	90,237	74,241
51	2057	44,255	279,005	323,259	-15,968	73,499	57,531
52	2058	44,890	298,117	343,006	-15,939	55,615	39,676
53	2059	45,553	318,538	364,091	-15,908	36,505	20,598
54	2060	0	250,970	250,970	-17,989	16,087	-1,902
55	**Total**	**$8,776,724**	**$9,687,254**	**$18,463,979**	**$3,807,302**	**$9,719,214**	**$13,273,658**

Table 12A: Generation Investments Placed in Service FY 2010
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1		Investment Placed in Service							Irrigation Assistance		
2	Fiscal Year	Initial Project	Replacements	Cumulative Amount in Service	Due Amortization	Discretionary Amortization	UnAmortized Investment	Term Investment Schedule	Cumulative Amount in Serivce	Amortization	Unamortized Amount
3	2009	333,152	-	4,470,376	92,990	10,075	4,367,311	5,417,603	683,690	7,274	676,416
4	2010	362,021	-	4,832,397	68	267,196	4,462,068	5,530,039	690,632	-	683,358
5	2011	380,900	120,494	5,333,791	-	161,888	4,801,574	5,841,316	697,198	-	689,924
6	2012	-	112,517	5,446,308	92,800	4,737	4,816,555	5,682,802	700,674	1,206	692,194
7	2013	-	105,066	5,551,374	70,000	20,097	4,831,523	5,577,868	720,467	60,027	651,960
8	2014	-	105,449	5,656,823	65,850	20,292	4,850,831	5,592,593	757,997	69,011	635,990
9	2015	-	105,852	5,762,675	32,300	-	4,924,383	5,546,145	763,104	151,285	515,198
10	2016	-	106,251	5,868,926	39,100	-	4,991,534	5,610,592	768,498	554	479,140
11	2017	-	106,715	5,975,641	-	-	5,098,249	5,651,181	803,751	1	514,392
12	2018	-	107,240	6,082,881	-	136,897	5,068,592	5,713,216	854,938	27,989	537,590
13	2019	-	107,824	6,190,705	40,000	568,869	4,567,546	5,696,268	865,840	58,168	490,324
14	2020	-	108,460	6,299,165	30,000	544,838	4,101,168	5,695,899	887,098	24,943	486,639
15	2021	-	109,147	6,408,312	-	620,602	3,589,713	5,721,198	926,305	12,354	513,492
16	2022	-	109,881	6,518,193	-	654,989	3,044,606	5,763,350	965,354	14,585	537,956
17	2023	-	97,810	6,616,003	-	690,757	2,451,659	5,688,147	994,434	13,252	553,784
18	2024	-	87,212	6,703,215	50,000	623,710	1,865,161	5,718,091	1,036,240	15,414	580,176
19	2025	-	77,863	6,781,078	70,000	543,405	1,329,619	5,486,464	1,056,277	13,900	586,313
20	2026	-	69,622	6,850,700	0	635,570	763,671	5,259,899	1,089,505	21,154	598,387
21	2027	-	62,363	6,913,063	-	426,353	399,681	5,211,151	1,121,733	192,572	438,043
22	2028	-	55,898	6,968,961	-	55,898	399,681	5,050,849	1,155,119	-	471,429
23	2029	-	50,186	7,019,147	-	50,186	399,681	4,843,614	1,199,916	-	516,226
24	2030	-	45,188	7,064,335	-	45,188	399,681	4,885,688	1,229,879	-	546,189
25	2031	-	40,741	7,105,076	30,000	40,741	369,681	4,884,077	1,259,842	-	576,152
26	2032	-	36,816	7,141,892	-	36,816	369,681	4,714,380	1,304,639	-	620,949
27	2033	-	52,599	7,194,491	20,000	52,599	349,681	4,467,650	1,345,063	-	661,373
28	2034	-	53,078	7,247,569	-	53,078	349,681	4,520,728	1,385,487	-	701,797
29	2035	-	53,600	7,301,169	-	53,600	349,681	4,526,114	1,414,694	-	731,004
30	2036	-	54,107	7,355,276	9,681	54,107	340,000	4,579,957	1,443,243	-	759,553
31	2037	-	54,656	7,409,932	-	54,656	340,000	4,562,077	1,471,951	-	788,261
32	2038	-	55,244	7,465,176	-	55,244	340,000	4,598,473	1,501,261	-	817,571
33	2039	-	55,872	7,521,048	45,000	55,872	295,000	4,654,345	1,530,572	-	846,882
34	2040	-	56,480	7,577,528	-	56,480	295,000	4,708,068	1,564,407	-	880,717
35	2041	-	57,125	7,634,653	30,000	57,125	265,000	4,756,442	1,598,243	-	914,553
36	2042	-	57,806	7,692,459	105,000	57,806	160,000	4,813,374	1,632,937	-	949,247
37	2043	-	54,460	7,746,919	50,000	54,460	110,000	4,710,356	1,667,632	-	983,942
38	2044	-	51,311	7,798,230	85,000	51,311	25,000	4,678,380	1,700,573	-	1,016,883
39	2045	-	48,402	7,846,632	25,000	48,402	(0)	4,623,965	1,733,514	-	1,049,824
40	2046	-	45,674	7,892,306	0	45,674	(0)	4,625,841	1,766,613	-	1,082,923
41	2047	-	43,118	7,935,424	(0)	43,118	(0)	4,599,643	1,806,338	-	1,122,648
42	2048	-	40,728	7,976,152	-	40,728	(0)	4,640,371	1,846,221	-	1,162,531
43	2049	-	36,747	8,012,899	0	36,747	(0)	4,633,118	1,886,104	-	1,202,414
44	2050	-	33,205	8,046,104	0	33,205	(0)	4,579,716	1,909,360	-	1,225,670
45	2051	-	30,083	8,076,187	(0)	30,083	(0)	4,500,864	1,932,775	-	1,249,085

Table 12A: Generation Investments Placed in Service FY 2010
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1		Investment Placed in Service							Irrigation Assistance		
2	Fiscal Year	Initial Project	Replacements	Cumulative Amount in Service	Due Amortization	Discretionary Amortization	UnAmortized Investment	Term Investment Schedule	Cumulative Amount in Serivce	Amortization	Unamortized Amount
46	2052	-	27,321	8,103,508	(0)	27,321	(0)	4,514,258	1,957,121	-	1,273,431
47	2053	-	42,785	8,146,293	(0)	42,785	(0)	4,481,457	1,988,437	-	1,304,747
48	2054	-	43,358	8,189,651	0	43,358	(0)	4,272,316	2,019,753	-	1,336,063
49	2055	-	43,962	8,233,613	(0)	43,962	(0)	3,985,752	2,051,069	-	1,367,379
50	2056	-	44,597	8,278,210	(0)	44,597	(0)	3,354,395	2,075,263	-	1,391,573
51	2057	-	45,216	8,323,426	(0)	45,216	(0)	3,229,664	2,075,263	-	1,391,573
52	2058	-	45,864	8,369,290	(0)	45,864	0	3,111,916	2,075,263	-	1,391,573
53	2059	-	46,542	8,415,832	-	46,542	0	3,053,009	2,075,263	-	1,391,573
54	2060	-	47,245	8,463,077	-	47,245	0	2,796,402	2,075,263	-	1,391,573
55	2061	-	-	8,463,077	-	-	0	2,594,151	2,075,263	-	1,391,573
56	**Total**	**$1,076,073**	**$3,249,780**	**-**	**$982,789**	**$7,480,288**	**-**	**-**		**$683,690**	**-**

Table 12B: Generation Federal Principal Payments FY 2010
($000s)

	A	B	C	D	E	F	G	H	I
1	**Fiscal Year**		**BPA Bonds**		**Corps of Engineers Appropriations**		**Bureau of Reclamation Appropriations**		**Irrigation Amortization**
2	2009		92,990		10,075		-		7,274
3	2010		68		266,346		850		-
4	2011		-		161,888		-		-
5	2012		92,800		4,737		-		1,206
6	2013		70,000		20,097		-		60,027
7	2014		65,850		20,292		-		69,011
8	2015		32,300		-		-		151,285
9	2016		39,100		-		-		554
10	2017		-		-		-		1
11	2018		-		92,700		44,197		27,989
12	2019		40,000		397,261		171,608		58,168
13	2020		30,000		355,560		189,278		24,943
14	2021		-		500,613		119,989		12,354
15	2022		-		654,989		-		14,585
16	2023		41,397		649,360		-		13,252
17	2024		390,968		201,755		80,986		15,414
18	2025		174,258		439,147		-		13,900
19	2026		76,850		542,760		15,961		21,154
20	2027		-		426,277		76		192,572
21	2028		-		55,898		-		-
22	2029		-		50,186		-		-
23	2030		-		45,188		-		-
24	2031		30,000		40,741		-		-
25	2032		-		36,816		-		-
26	2033		20,000		52,599		-		-
27	2034		-		53,078		-		-
28	2035		-		53,600		-		-
29	2036		9,681		54,107		-		-
30	2037		-		54,656		-		-
31	2038		-		55,244		-		-
32	2039		45,000		55,872		-		-
33	2040		-		56,480		-		-
34	2041		30,000		57,125		-		-
35	2042		105,000		57,806		-		-
36	2043		50,000		54,460		-		-
37	2044		85,000		51,311		-		-
38	2045		25,000		48,402		0		-
39	2046		-		45,674		0		-
40	2047		-		43,118		0		-
41	2048		-		40,728		-		-
42	2049		-		36,747		-		-
43	2050		-		33,205		-		-
44	2051		-		30,083		(0)		-
45	2052		-		27,321		-		-
46	2053		-		42,785		-		-
47	2054		-		43,358		-		-
48	2055		-		43,962		0		-
49	2056		-		44,597		-		-
50	2057		-		45,216		0		-
51	2058		-		45,864		(0)		-
52	2059		-		46,542		-		-
53	2060		-		47,245		-		-
54	2061		-		-		-		-
55	**Total**		**$1,546,262**		**$6,293,869**		**$622,946**		**$683,690**

Table 12C: Generation Component of Capitalized Contract Principal Payments FY 2011
($000s)

	A	B	C	D	E	F	G
1	**Fiscal Year**		**EN**		**Other**		**Total**
2	2009		265,499		10,161		275,660
3	2010		275,047		10,647		285,694
4	2011		310,343		11,148		321,492
5	2012		411,702		11,699		423,401
6	2013		370,869		12,277		383,146
7	2014		389,465		12,895		402,360
8	2015		399,071		8,818		407,888
9	2016		553,635		8,943		562,579
10	2017		618,597		9,403		628,000
11	2018		488,765		9,873		498,638
12	2019		33,474		10,367		43,840
13	2020		135,634		10,886		146,520
14	2021		142,656		11,435		154,091
15	2022		149,974		12,014		161,988
16	2023		157,683		13,028		170,711
17	2024		131,020		13,683		144,702
18	2025		33,483		353		33,835
19	2026		35,777		0		35,777
20	2027		38,228		0		38,228
21	2028		40,846		0		40,846
22	2029		43,644		0		43,644
23	2030		46,634		0		46,634
24	2031		49,828		0		49,828
25	2032		53,242		0		53,242
26	2033		56,889		0		56,889
27	2034		60,785		0		60,785
28	2035		64,949		0		64,949
29	2036		69,398		0		69,398
30	2037		74,152		0		74,152
31	2038		79,231		0		79,231
32	2039		84,659		0		84,659
33	2040		90,458		0		90,458
34	2041		96,654		0		96,654
35	2042		103,275		0		103,275
36	2043		110,349		0		110,349
37	2044		117,908		0		117,908
38	2045		125,984		0		125,984
39	2046		134,615		0		134,615
40	2047		143,836		0		143,836
41	2048		153,689		0		153,689
42	2049		164,216		0		164,216
43	2050		175,465		0		175,465
44	2051		187,485		0		187,485
45	2052		200,327		0		200,327
46	2053		214,049		0		214,049
47	2054		228,712		0		228,712
48	2055		244,379		0		244,379
49	2056		261,118		0		261,118

Table 12C: Generation Component of Capitalized Contract Principal Payments FY 2011
($000s)

	A	B	C	D	E	F	G
1	**Fiscal Year**		**EN**		**Other**		**Total**
50	2057		279,005		0		279,005
51	2058		298,117		0		298,117
52	2059		318,538		0		318,538
53	2060		250,970		0		250,970
54	2061		0				
55	**Total**		**$9,564,322**		**$177,628**		**$9,741,949**

Table 12D: Generation Federal Interest Payments FY 2011
($000s)

	A	B	C	D	E	F	G
1	**Fiscal Year**		**BPA Bonds (1)**		**Corps of Engineers Appropriations (2)**		**Bureau of Reclamation Appropriations**
2	2009		34,814		174,856		43,187
3	2010		38,174		178,944		43,187
4	2011		59,200		164,396		43,126
5	2012		73,980		166,467		43,126
6	2013		71,898		173,756		43,126
7	2014		67,667		179,441		43,126
8	2015		64,497		185,137		43,126
9	2016		66,083		192,314		43,126
10	2017		64,684		199,518		43,126
11	2018		60,707		206,753		43,126
12	2019		49,164		207,396		39,962
13	2020		49,361		186,302		27,691
14	2021		47,780		168,233		14,158
15	2022		47,780		140,203		5,579
16	2023		49,893		103,245		5,579
17	2024		61,045		65,850		5,579
18	2025		25,102		58,904		821
19	2026		15,608		39,201		821
20	2027		8,967		16,171		3
21	2028		8,971		-		-
22	2029		8,975		-		-
23	2030		8,980		-		-
24	2031		8,985		-		-
25	2032		7,251		-		-
26	2033		7,256		-		-
27	2034		5,947		-		-
28	2035		5,953		-		-
29	2036		5,960		-		-
30	2037		5,382		-		-
31	2038		5,390		-		-
32	2039		5,398		-		-
33	2040		2,894		-		-
34	2041		2,903		-		-
35	2042		837		-		-
36	2043		(6,405)		-		-
37	2044		(9,413)		-		-
38	2045		(15,010)		-		-
39	2046		(16,697)		-		-
40	2047		(16,683)		-		-
41	2048		(16,668)		-		-
42	2049		(16,652)		-		-
43	2050		(16,635)		-		-
44	2051		(16,617)		-		-
45	2052		(16,597)		-		-
46	2053		(16,576)		-		-
47	2054		(16,554)		-		-
48	2055		(16,530)		-		-
49	2056		(16,505)		-		-
50	2057		(16,478)		-		-
51	2058		(16,449)		-		-
52	2059		(16,418)		-		-
53	2060		(18,499)		-		-
54	2061		(24,814)		-		-
55	**Total**		**$741,286**		**$2,807,085**		**$531,576**

Table 12E: Generation Component of Capitalized Contract Interest Payments FY 2011
($000s)

	A	B	C	D	E	F	G
1	**Fiscal Year**		**EN**		**Other**		**Total**
2	2009		279,794		8,765		288,559
3	2010		262,160		8,198		270,358
4	2011		247,339		7,534		254,873
5	2012		236,251		6,977		243,228
6	2013		220,499		6,378		226,877
7	2014		195,418		5,750		201,168
8	2015		159,572		5,209		164,780
9	2016		140,490		4,763		145,253
10	2017		109,365		4,301		113,666
11	2018		71,061		3,816		74,877
12	2019		38,268		3,307		41,575
13	2020		36,533		2,772		39,306
14	2021		29,518		2,211		31,729
15	2022		22,188		1,621		23,809
16	2023		14,479		991		15,470
17	2024		82,272		341		82,613
18	2025		303,250		9		303,259
19	2026		301,104		0		301,104
20	2027		298,810		0		298,810
21	2028		296,360		0		296,360
22	2029		293,742		0		293,742
23	2030		290,944		0		290,944
24	2031		287,955		0		287,955
25	2032		284,761		0		284,761
26	2033		281,348		0		281,348
27	2034		277,702		0		277,702
28	2035		273,805		0		273,805
29	2036		269,642		0		269,642
30	2037		265,194		0		265,194
31	2038		260,441		0		260,441
32	2039		255,362		0		255,362
33	2040		249,935		0		249,935
34	2041		244,137		0		244,137
35	2042		237,941		0		237,941
36	2043		231,321		0		231,321
37	2044		224,248		0		224,248
38	2045		216,690		0		216,690
39	2046		208,615		0		208,615
40	2047		199,986		0		199,986
41	2048		190,766		0		190,766
42	2049		180,915		0		180,915
43	2050		170,388		0		170,388
44	2051		159,141		0		159,141
45	2052		147,123		0		147,123
46	2053		134,282		0		134,282
47	2054		120,562		0		120,562
48	2055		105,901		0		105,901
49	2056		90,237		0		90,237
50	2057		73,499		0		73,499
51	2058		55,615		0		55,615
52	2059		36,505		0		36,505
53	2060		16,087		0		16,087
54	2061		0		0		0
55	**Total**		**$9,679,523**		**$72,943**		**$9,752,466**

Table 12F: Generation Summary of Payments FY 2011
($000s)

	A	B	C	D	E	F	G
1		Principal			Interest		
2	Fiscal Year	Generation Payment	Capitalized Contracts Payment	Total Principal Payment	Generation Payment	Capitalized Contracts Payment	Total Interest Payment
3	2009	110,339	275,660	385,999	252,858	288,559	288,559
4	2010	267,264	285,694	552,958	260,305	270,358	530,663
5	2011	161,888	321,492	483,380	266,721	254,873	521,595
6	2012	98,743	423,401	522,144	283,573	243,228	526,801
7	2013	150,124	383,146	533,270	288,780	226,877	515,657
8	2014	155,153	402,360	557,513	290,233	201,168	491,402
9	2015	183,585	407,888	591,473	292,761	164,780	457,541
10	2016	39,654	562,579	602,233	301,523	145,253	446,775
11	2017	1	628,000	628,001	307,327	113,666	420,993
12	2018	164,886	498,638	663,524	310,586	74,877	385,463
13	2019	667,037	43,840	710,878	296,521	41,575	338,096
14	2020	599,781	146,520	746,301	263,355	39,306	302,661
15	2021	632,956	154,091	787,047	230,171	31,729	261,900
16	2022	669,574	161,988	831,562	193,562	23,809	217,371
17	2023	704,009	170,711	874,720	158,717	15,470	174,188
18	2024	689,124	144,702	833,826	132,474	82,613	215,087
19	2025	627,305	33,835	661,140	84,827	303,259	388,086
20	2026	656,724	35,777	692,501	55,630	301,104	356,734
21	2027	618,925	38,228	657,152	25,142	298,810	323,952
22	2028	55,898	40,846	96,744	8,971	296,360	305,331
23	2029	50,186	43,644	93,830	8,975	293,742	302,717
24	2030	45,188	46,634	91,822	8,980	290,944	299,924
25	2031	70,741	49,828	120,569	8,985	287,955	296,940
26	2032	36,816	53,242	90,058	7,251	284,761	292,012
27	2033	72,599	56,889	129,488	7,256	281,348	288,604
28	2034	53,078	60,785	113,863	5,947	277,702	283,648
29	2035	53,600	64,949	118,549	5,953	273,805	279,758
30	2036	63,788	69,398	133,186	5,960	269,642	275,602
31	2037	54,656	74,152	128,808	5,382	265,194	270,576
32	2038	55,244	79,231	134,475	5,390	260,441	265,831
33	2039	100,872	84,659	185,531	5,398	255,362	260,760
34	2040	56,480	90,458	146,938	2,894	249,935	252,829
35	2041	87,125	96,654	183,779	2,903	244,137	247,040
36	2042	162,806	103,275	266,081	837	237,941	238,778
37	2043	104,460	110,349	214,809	-6,405	231,321	224,916
38	2044	136,311	117,908	254,219	-9,413	224,248	214,835
39	2045	73,402	125,984	199,386	-15,010	216,690	201,680
40	2046	45,674	134,615	180,289	-16,697	208,615	191,918
41	2047	43,118	143,836	186,954	-16,683	199,986	183,303
42	2048	40,728	153,689	194,417	-16,668	190,766	174,098
43	2049	36,747	164,216	200,963	-16,652	180,915	164,262
44	2050	33,205	175,465	208,670	-16,635	170,388	153,753
45	2051	30,083	187,485	217,567	-16,617	159,141	142,524
46	2052	27,321	200,327	227,648	-16,597	147,123	130,526
47	2053	42,785	214,049	256,834	-16,576	134,282	117,706
48	2054	43,358	228,712	272,070	-16,554	120,562	104,008
49	2055	43,962	244,379	288,340	-16,530	105,901	89,371
50	2056	44,597	261,118	305,715	-16,505	90,237	73,732
51	2057	45,216	279,005	324,220	-16,478	73,499	57,021
52	2058	45,864	298,117	343,980	-16,449	55,615	39,166
53	2059	46,542	318,538	365,080	-16,418	36,505	20,088
54	2060	47,245	250,970	298,215	-18,499	16,087	-2,411
55	2061	0	0	0	-24,814	0	-24,814
56	**Total**	**$9,146,767**	**$9,741,949**	**$18,888,717**	**$4,079,947**	**$9,752,466**	**$13,579,555**

Table 13: Application of Amortization FY 2011
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1	**Date**	**Project**	**In Service**	**Due**	**Original Balance**	**Amount Available**	**Rate**	**Replacement?**	**Rollover?**	**Amount Amortized**	
2	FY 2009	CONSERVATION	1989	2009	40,000	40,000	8.550%	No	No	40,000	
3	FY 2009	BUREAU DIRECT FUND	2006	2009	25,000	25,000	5.050%	No	No	25,000	
4	FY 2009	CONSERVATION	2006	2009	20,000	20,000	5.050%	No	No	20,000	
5	FY 2009	BPA PROGRAM	2005	2009	7,990	7,990	3.750%	No	No	7,990	
6	FY 2009	LOWER MONUMENTAL	1970	2020	51,218	35,036	7.250%	No	No	7,150	
7	FY 2009	LOWER MONUMENTAL	1971	2020	214	214	7.250%	Yes	No	214	
8	FY 2009	LOWER MONUMENTAL	1972	2020	214	214	7.250%	Yes	No	214	
9	FY 2009	LOWER MONUMENTAL	1973	2020	214	214	7.250%	Yes	No	214	
10	FY 2009	LOWER MONUMENTAL	1974	2020	214	214	7.250%	Yes	No	214	
11	FY 2009	LOWER MONUMENTAL	1975	2020	214	214	7.250%	Yes	No	214	
12	FY 2009	LOWER MONUMENTAL	1976	2020	214	214	7.250%	Yes	No	214	
13	FY 2009	LOWER MONUMENTAL	1977	2020	214	214	7.250%	Yes	No	214	
14	FY 2009	LOWER MONUMENTAL	1978	2020	214	214	7.250%	Yes	No	214	
15	FY 2009	LOWER MONUMENTAL	1979	2020	214	214	7.250%	Yes	No	214	
16	FY 2009	LOWER MONUMENTAL	1980	2020	214	214	7.250%	Yes	No	214	
17	FY 2009	LOWER MONUMENTAL	1981	2020	214	214	7.250%	Yes	No	214	
18	FY 2009	LOWER MONUMENTAL	1982	2020	214	214	7.250%	Yes	No	214	
19	FY 2009	LOWER MONUMENTAL	1983	2020	214	214	7.250%	Yes	No	214	
20	FY 2009	LOWER MONUMENTAL	1985	2020	8	8	7.250%	No	No	8	
21	FY 2009	LOWER MONUMENTAL	1986	2020	132	132	7.250%	No	No	132	
22	FY 2009	LOWER MONUMENTAL	1987	2020	3	3	7.250%	No	No	3	
23	**Subtotal**		-	-	**$147,133**	**$130,951**	-	**Yes**	**No**	**$103,065**	
24											
25	FY 2010	BPA PROGRAM	2001	2010	68	68	6.050%	No	No	68	
26	FY 2010	LOWER MONUMENTAL	1970	2020	51,218	27,886	7.250%	No	No	27,886	
27	FY 2010	DWORSHAK	1996	2021	26	26	7.230%	No	No	26	
28	FY 2010	DWORSHAK	1996	2021	184	184	7.230%	No	No	184	
29	FY 2010	JOHN DAY	1971	2021	34,974	34,974	7.230%	No	No	34,974	
30	FY 2010	LITTLE GOOSE	1971	2021	42,962	42,962	7.230%	No	No	42,962	
31	FY 2010	LITTLE GOOSE	1972	2021	28	28	7.230%	Yes	No	28	
32	FY 2010	LITTLE GOOSE	1973	2021	29	29	7.230%	Yes	No	29	
33	FY 2010	LITTLE GOOSE	1974	2021	28	28	7.230%	Yes	No	28	
34	FY 2010	LITTLE GOOSE	1975	2021	29	29	7.230%	Yes	No	29	
35	FY 2010	LITTLE GOOSE	1976	2021	28	28	7.230%	Yes	No	28	
36	FY 2010	LITTLE GOOSE	1977	2021	29	29	7.230%	Yes	No	29	
37	FY 2010	LITTLE GOOSE	1978	2021	28	28	7.230%	Yes	No	28	
38	FY 2010	LITTLE GOOSE	1979	2021	29	29	7.230%	Yes	No	29	
39	FY 2010	LITTLE GOOSE	1980	2021	28	28	7.230%	Yes	No	28	
40	FY 2010	LITTLE GOOSE	1981	2021	29	29	7.230%	Yes	No	29	
41	FY 2010	LITTLE GOOSE	1982	2021	28	28	7.230%	Yes	No	28	
42	FY 2010	LITTLE GOOSE	1983	2021	29	29	7.230%	Yes	No	29	
43	FY 2010	LITTLE GOOSE	1985	2021	174	174	7.230%	No	No	174	
44	FY 2010	LITTLE GOOSE	1986	2021	239	239	7.230%	No	No	239	
45	FY 2010	LITTLE GOOSE	1987	2021	6	6	7.230%	No	No	6	
46	FY 2010	LOWER MONUMENTAL	1996	2021	37	37	7.230%	No	No	37	
47	FY 2010	LOWER MONUMENTAL	1996	2021	51	51	7.230%	No	No	51	
48	FY 2010	BONNEVILLE	1997	2022	122	122	7.230%	No	No	122	
49	FY 2010	ICE HARBOR	1997	2022	66	66	7.230%	No	No	66	
50	FY 2010	JOHN DAY	1997	2022	133	133	7.230%	No	No	133	
51	FY 2010	LIBBY	1997	2022	432	432	7.230%	No	No	432	
52	FY 2010	JOHN DAY	1972	2022	11,502	11,502	7.210%	No	No	11,502	
53	FY 2010	JOHN DAY	1985	2022	6,490	6,490	7.210%	No	No	6,490	
54	FY 2010	JOHN DAY	1986	2022	3,227	3,227	7.210%	No	No	3,227	
55	FY 2010	JOHN DAY	1987	2022	706	706	7.210%	No	No	706	
56	FY 2010	JOHN DAY	1989	2022	30	30	7.210%	No	No	30	
57	FY 2010	JOHN DAY	1990	2022	37	37	7.210%	No	No	37	
58	FY 2010	JOHN DAY	1992	2022	19	19	7.210%	No	No	19	
59	FY 2010	YAKIMA-CHANDLER	1956	2022	1,068	193	7.210%	No	No	193	
60	FY 2010	YAKIMA-CHANDLER	1956	2022	481	216	7.210%	No	No	216	
61	FY 2010	YAKIMA-CHANDLER	1959	2022	1	1	7.210%	Yes	No	1	
62	FY 2010	YAKIMA-CHANDLER	1960	2022	1	1	7.210%	Yes	No	1	
63	FY 2010	YAKIMA-CHANDLER	1961	2022	1	1	7.210%	Yes	No	1	
64	FY 2010	YAKIMA-CHANDLER	1986	2022	456	438	7.210%	No	No	438	
65	FY 2010	DWORSHAK	1973	2023	138,443	132,996	7.190%	No	No	107,360	
66	FY 2010	DWORSHAK	1973	2023	836	803	7.190%	No	No	803	
67	FY 2010	DWORSHAK	1974	2023	515	515	7.190%	Yes	No	515	
68	FY 2010	DWORSHAK	1974	2023	3	3	7.190%	Yes	No	3	
69	FY 2010	DWORSHAK	1975	2023	518	518	7.190%	Yes	No	518	
70	FY 2010	DWORSHAK	1975	2023	3	3	7.190%	Yes	No	3	
71	FY 2010	DWORSHAK	1976	2023	518	518	7.190%	Yes	No	518	
72	FY 2010	DWORSHAK	1976	2023	3	3	7.190%	Yes	No	3	
73	FY 2010	DWORSHAK	1977	2023	518	518	7.190%	Yes	No	518	
74	FY 2010	DWORSHAK	1977	2023	3	3	7.190%	Yes	No	3	
75	FY 2010	DWORSHAK	1978	2023	518	518	7.190%	Yes	No	518	
76	FY 2010	DWORSHAK	1978	2023	3	3	7.190%	Yes	No	3	
77	FY 2010	DWORSHAK	1979	2023	518	518	7.190%	Yes	No	518	
78	FY 2010	DWORSHAK	1979	2023	3	3	7.190%	Yes	No	3	
79	FY 2010	DWORSHAK	1980	2023	518	518	7.190%	Yes	No	518	
80	FY 2010	DWORSHAK	1980	2023	3	3	7.190%	Yes	No	3	
81	FY 2010	DWORSHAK	1981	2023	518	518	7.190%	Yes	No	518	
82	FY 2010	DWORSHAK	1981	2023	3	3	7.190%	Yes	No	3	
83	FY 2010	DWORSHAK	1982	2023	518	518	7.190%	Yes	No	518	
84	FY 2010	DWORSHAK	1982	2023	3	3	7.190%	Yes	No	3	
85	FY 2010	DWORSHAK	1983	2023	523	523	7.190%	Yes	No	523	
86	FY 2010	DWORSHAK	1983	2023	3	3	7.190%	Yes	No	3	
87	FY 2010	DWORSHAK	1985	2023	1,141	1,141	7.190%	No	No	1,141	
88	FY 2010	DWORSHAK	1986	2023	197	197	7.190%	No	No	197	
89	FY 2010	DWORSHAK	1987	2023	36	5	7.190%	No	No	5	
90	FY 2010	THE DALLES	1973	2023	21,983	21,983	7.190%	No	No	21,983	
91	**Subtotal**		-	-	**$322,901**	**$292,900**	-	**Yes**	**No**	**$267,264**	
92											
93	FY 2011	HILLS CREEK	1962	2012	10,353	5,159	7.160%	No	No	5,159	

Table 13: Application of Amortization FY 2011
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
94	FY 2011	HILLS CREEK	1974	2012	13	13	7.160%	Yes	No	13	
95	FY 2011	HILLS CREEK	1977	2012	13	13	7.160%	Yes	No	13	
96	FY 2011	HILLS CREEK	1978	2012	13	13	7.160%	Yes	No	13	
97	FY 2011	HILLS CREEK	1979	2012	13	13	7.160%	Yes	No	13	
98	FY 2011	HILLS CREEK	1980	2012	13	13	7.160%	Yes	No	13	
99	FY 2011	HILLS CREEK	1981	2012	13	13	7.160%	Yes	No	13	
100	FY 2011	HILLS CREEK	1982	2012	13	13	7.160%	Yes	No	13	
101	FY 2011	HILLS CREEK	1983	2012	13	13	7.160%	Yes	No	13	
102	FY 2011	ICE HARBOR	1973	2012	1	1	7.160%	Yes	No	1	
103	FY 2011	DWORSHAK	1973	2023	138,443	25,636	7.190%	No	No	25,636	
104	FY 2011	THE DALLES	1974	2024	7,268	7,268	7.170%	No	No	7,268	
105	FY 2011	LIBBY	1975	2025	54,644	48,138	7.160%	No	No	1,348	
106	FY 2011	LOWER GRANITE	1975	2025	119,237	117,645	7.160%	No	No	117,645	
107	FY 2011	LOWER GRANITE	1976	2025	510	510	7.160%	Yes	No	510	
108	FY 2011	LOWER GRANITE	1977	2025	510	510	7.160%	Yes	No	510	
109	FY 2011	LOWER GRANITE	1978	2025	510	510	7.160%	Yes	No	510	
110	FY 2011	LOWER GRANITE	1979	2025	510	510	7.160%	Yes	No	510	
111	FY 2011	LOWER GRANITE	1980	2025	510	510	7.160%	Yes	No	510	
112	FY 2011	LOWER GRANITE	1981	2025	510	510	7.160%	Yes	No	510	
113	FY 2011	LOWER GRANITE	1982	2025	510	510	7.160%	Yes	No	510	
114	FY 2011	LOWER GRANITE	1983	2025	510	510	7.160%	Yes	No	510	
115	FY 2011	LOWER GRANITE	1985	2025	328	328	7.160%	No	No	328	
116	FY 2011	LOWER GRANITE	1986	2025	215	215	7.160%	No	No	215	
117	FY 2011	LOWER GRANITE	1987	2025	8	8	7.160%	No	No	8	
118	FY 2011	LOWER GRANITE	1995	2025	96	96	7.160%	No	No	96	
119	**Subtotal**		-	-	**$334,777**	**$208,678**	-	**Yes**	**No**	**$161,888**	
120											
121	FY 2012	CONSERVATION	1998	2012	52,800	52,800	5.600%	No	No	52,800	
122	FY 2012	CONSERVATION	2007	2012	20,000	20,000	4.130%	No	Yes	20,000	
123	FY 2012	FISH, WILDLIFE	2008	2012	20,000	20,000	3.444%	No	No	20,000	
124	FY 2012	LIBBY	1975	2025	54,644	46,790	7.160%	No	No	4,737	
125	**Subtotal**		-	-	**$147,444**	**$139,590**	-	**No**	**Yes**	**$97,537**	
126											
127	FY 2013	FISH, WILDLIFE	1998	2013	60,000	60,000	6.100%	No	No	60,000	
128	FY 2013	CONSERVATION	2008	2013	10,000	10,000	3.701%	No	No	10,000	
129	FY 2013	LIBBY	1975	2025	54,644	42,054	7.160%	No	No	20,097	
130	**Subtotal**		-	-	**$124,644**	**$112,054**	-	**No**	**No**	**$90,097**	
131											
132	FY 2014	BPA PROGRAM	1999	2014	950	950	5.900%	No	No	950	
133	FY 2014	CONSERVATION	2009	2014	27,200	27,200	3.660%	No	No	27,200	
134	FY 2014	CONSERVATION	1998	2014	37,700	37,700	3.600%	No	Yes	37,700	
135	FY 2014	LIBBY	1975	2025	54,644	21,956	7.160%	No	No	20,292	
136	**Subtotal**		-	-	**$120,494**	**$87,806**	-	**No**	**Yes**	**$86,142**	
137											
138	FY 2015	CONSERVATION	2010	2015	32,300	32,300	4.930%	No	No	32,300	
139	**Subtotal**		-	-	**$32,300**	**$32,300**	-	**No**	**No**	**$32,300**	
140											
141	FY 2016	CONSERVATION	2011	2016	39,100	39,100	5.560%	No	No	39,100	
142	**Subtotal**		-	-	**$39,100**	**$39,100**	-	**No**	**No**	**$39,100**	
143											
144	FY 2018	COLUMBIA BASIN - 3RD PWR HOUSE	1975	2025	47,328	36,690	7.160%	No	No	36,690	
145	FY 2018	COLUMBIA BASIN - 3RD PWR HOUSE	1975	2025	8,702	7,435	7.160%	No	No	7,435	
146	FY 2018	LIBBY	1975	2025	54,644	1,665	7.160%	No	No	1,665	
147	FY 2018	COLUMBIA BASIN	1996	2026	72	72	7.150%	No	No	72	
148	FY 2018	ICE HARBOR	1985	2026	21	21	7.150%	No	No	21	
149	FY 2018	LIBBY	1976	2026	153,432	153,432	7.150%	No	No	79,604	
150	FY 2018	LIBBY	1977	2026	1,465	1,465	7.150%	Yes	No	1,465	
151	FY 2018	LIBBY	1978	2026	1,465	1,465	7.150%	Yes	No	1,465	
152	FY 2018	LIBBY	1979	2026	1,465	1,465	7.150%	Yes	No	1,465	
153	FY 2018	LIBBY	1980	2026	1,465	1,465	7.150%	Yes	No	1,465	
154	FY 2018	LIBBY	1981	2026	1,465	1,465	7.150%	Yes	No	1,465	
155	FY 2018	LIBBY	1982	2026	1,465	1,465	7.150%	Yes	No	1,465	
156	FY 2018	LIBBY	1983	2026	1,465	1,465	7.150%	Yes	No	1,465	
157	FY 2018	LIBBY	1985	2026	518	518	7.150%	No	No	518	
158	FY 2018	LIBBY	1986	2026	283	283	7.150%	No	No	283	
159	FY 2018	LIBBY	1987	2026	2	2	7.150%	No	No	2	
160	FY 2018	LIBBY	1989	2026	1	1	7.150%	No	No	1	
161	FY 2018	MCNARY	1996	2026	74	74	7.150%	No	No	74	
162	FY 2018	MCNARY	1996	2026	277	277	7.150%	No	No	277	
163	**Subtotal**		-	-	**$275,609**	**$210,725**	-	**Yes**	**No**	**$136,897**	
164											
165	FY 2019	FISH, WILDLIFE	2007	2019	20,000	20,000	5.690%	No	Yes	20,000	
166	FY 2019	FISH, WILDLIFE	2006	2019	20,000	20,000	5.070%	No	Yes	20,000	
167	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1976	2026	41,330	41,330	7.150%	No	No	41,330	
168	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1976	2026	8,037	8,037	7.150%	No	No	8,037	
169	FY 2019	ICE HARBOR	1976	2026	20,472	20,472	7.150%	No	No	20,472	
170	FY 2019	ICE HARBOR	1976	2026	228	228	7.150%	No	No	228	
171	FY 2019	LIBBY	1976	2026	153,432	73,828	7.150%	No	No	73,828	
172	FY 2019	CHIEF JOSEPH	1977	2027	30,512	30,512	7.150%	No	No	30,512	
173	FY 2019	BONNEVILLE	1977	2027	15,670	15,670	7.150%	No	No	15,670	
174	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1977	2027	42,764	42,764	7.150%	No	No	42,764	
175	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1977	2027	7,964	7,964	7.150%	No	No	7,964	
176	FY 2019	LOST CREEK	1977	2027	13,505	13,413	7.150%	No	No	13,413	
177	FY 2019	LOST CREEK	1978	2027	58	58	7.150%	Yes	No	58	
178	FY 2019	LOST CREEK	1979	2027	60	60	7.150%	Yes	No	60	
179	FY 2019	LOST CREEK	1980	2027	60	60	7.150%	Yes	No	60	
180	FY 2019	LOST CREEK	1981	2027	60	60	7.150%	Yes	No	60	
181	FY 2019	LOST CREEK	1982	2027	60	60	7.150%	Yes	No	60	
182	FY 2019	LOST CREEK	1983	2027	60	60	7.150%	Yes	No	60	
183	FY 2019	LOST CREEK	1985	2027	12	12	7.150%	No	No	12	
184	FY 2019	LOST CREEK	1986	2027	6	6	7.150%	No	No	6	
185	FY 2019	LOST CREEK	1987	2027	4	4	7.150%	No	No	4	
186	FY 2019	CHIEF JOSEPH	1978	2028	75,669	75,669	7.150%	No	No	75,669	

Table 13: Application of Amortization FY 2011
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
187	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1978	2028	42,399	42,399	7.150%	No	No	42,399	
188	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1978	2028	7,896	7,896	7.150%	No	No	7,896	
189	FY 2019	LITTLE GOOSE	1978	2028	49,578	49,578	7.150%	No	No	49,578	
190	FY 2019	LITTLE GOOSE	1985	2028	47	47	7.150%	No	No	47	
191	FY 2019	LOWER GRANITE	1978	2028	40,611	40,611	7.150%	No	No	40,611	
192	FY 2019	CHIEF JOSEPH	1985	2029	16,372	16,372	7.150%	No	No	16,372	
193	FY 2019	CHIEF JOSEPH	1986	2029	5,363	5,363	7.150%	No	No	5,363	
194	FY 2019	CHIEF JOSEPH	1987	2029	3,036	3,036	7.150%	No	No	3,036	
195	FY 2019	CHIEF JOSEPH	1988	2029	2,722	2,722	7.150%	No	No	2,722	
196	FY 2019	CHIEF JOSEPH	1989	2029	2,227	2,227	7.150%	No	No	2,227	
197	FY 2019	CHIEF JOSEPH	1990	2029	4,505	4,505	7.150%	No	No	4,505	
198	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1979	2029	84,118	84,118	7.150%	No	No	5,552	
199	FY 2019	COLUMBIA BASIN - 3RD PWR HOUSE	1979	2029	15,666	15,666	7.150%	No	No	15,666	
200	FY 2019	LIBBY	1994	2029	286	152	7.150%	No	No	152	
201	FY 2019	LOWER GRANITE	1994	2029	3,543	1,551	7.150%	No	No	1,551	
202	FY 2019	LOWER MONUMENTAL	1979	2029	40,669	40,669	7.150%	No	No	40,669	
203	FY 2019	LOWER MONUMENTAL	1985	2029	256	256	7.150%	No	No	256	
204	**Subtotal**		-	-	**$769,257**	**$687,435**	-	**Yes**	**Yes**	**$608,869**	
205											
206	FY 2020	FISH, WILDLIFE	2007	2020	30,000	30,000	5.210%	No	Yes	30,000	
207	FY 2020	CHIEF JOSEPH	1979	2029	60,079	60,079	7.150%	No	No	60,079	
208	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1979	2029	84,118	78,566	7.150%	No	No	78,566	
209	FY 2020	DWORSHAK	1995	2030	218	218	7.150%	No	No	218	
210	FY 2020	HUNGRY HORSE	1995	2030	536	536	7.150%	Yes	No	536	
211	FY 2020	HUNGRY HORSE	1995	2030	1,198	1,195	7.150%	Yes	No	1,195	
212	FY 2020	LIBBY	1995	2030	15	15	7.150%	Yes	No	15	
213	FY 2020	LIBBY	1995	2030	41	41	7.150%	No	No	41	
214	FY 2020	LIBBY	1995	2030	94	94	7.150%	Yes	No	94	
215	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1981	2031	40,964	40,964	7.150%	No	No	40,964	
216	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1981	2031	455	455	7.150%	No	No	455	
217	FY 2020	CHIEF JOSEPH	1996	2031	27	27	7.150%	Yes	No	27	
218	FY 2020	BONNEVILLE	1996	2031	22	22	7.150%	No	No	22	
219	FY 2020	COLUMBIA BASIN	1996	2031	109	109	7.150%	No	No	109	
220	FY 2020	COLUMBIA BASIN	1996	2031	251	251	7.150%	No	No	251	
221	FY 2020	DWORSHAK	1996	2031	6	6	7.150%	No	No	6	
222	FY 2020	DWORSHAK	1996	2031	203	203	7.150%	No	No	203	
223	FY 2020	ICE HARBOR	1996	2031	78	78	7.150%	No	No	78	
224	FY 2020	LOST CREEK	1996	2031	31	31	7.150%	No	No	31	
225	FY 2020	LOWER GRANITE	1996	2031	206	206	7.150%	No	No	206	
226	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1982	2032	203,535	203,535	7.150%	No	No	203,535	
227	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1982	2032	2,264	2,264	7.150%	No	No	2,264	
228	FY 2020	CHIEF JOSEPH	1997	2032	166	166	7.150%	No	No	166	
229	FY 2020	BONNEVILLE	1997	2032	518	518	7.150%	No	No	518	
230	FY 2020	MCNARY	1997	2032	30	30	7.150%	No	No	30	
231	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1985	2033	9,138	9,138	7.150%	No	No	9,138	
232	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1986	2033	30,578	30,578	7.150%	No	No	30,578	
233	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1987	2033	2,801	2,801	7.150%	No	No	2,801	
234	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1988	2033	1,271	1,271	7.150%	No	No	1,271	
235	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1989	2033	1,232	1,232	7.150%	No	No	1,232	
236	FY 2020	BONNEVILLE - 2ND POWER HOUSE	1990	2033	1,588	1,588	7.150%	No	No	1,588	
237	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1984	2033	13,192	13,192	7.150%	No	No	4,034	
238	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1984	2033	3,160	3,160	7.150%	No	No	3,160	
239	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1985	2033	2,060	2,060	7.150%	No	No	2,060	
240	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1985	2033	41,772	41,772	7.150%	No	No	41,772	
241	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1985	2033	107	107	7.150%	No	No	107	
242	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1986	2033	1,851	1,851	7.150%	No	No	1,851	
243	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1986	2033	15,538	15,538	7.150%	No	No	15,538	
244	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1987	2033	1,730	1,730	7.150%	No	No	1,730	
245	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1987	2033	14,439	14,439	7.150%	No	No	14,439	
246	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1988	2033	2,294	2,294	7.150%	No	No	2,294	
247	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1988	2033	4,351	4,351	7.150%	No	No	4,351	
248	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1989	2033	10,902	10,902	7.150%	No	No	10,902	
249	FY 2020	COLUMBIA BASIN - 3RD PWR HOUSE	1990	2033	6,383	6,383	7.150%	No	No	6,383	
250	**Subtotal**		-	-	**$589,551**	**$583,996**	-	**Yes**	**Yes**	**$574,838**	
251											
252	FY 2021	BONNEVILLE - 2ND POWER HOUSE	1983	2033	62,409	62,409	7.150%	No	No	62,409	
253	FY 2021	BONNEVILLE - 2ND POWER HOUSE	1983	2033	694	694	7.150%	No	No	694	
254	FY 2021	COLUMBIA BASIN - 3RD PWR HOUSE	1983	2033	712	712	7.150%	No	No	712	
255	FY 2021	COLUMBIA BASIN - 3RD PWR HOUSE	1983	2033	13,003	13,003	7.150%	No	No	13,003	
256	FY 2021	COLUMBIA BASIN - 3RD PWR HOUSE	1984	2033	16,965	16,965	7.150%	No	No	16,965	
257	FY 2021	COLUMBIA BASIN - 3RD PWR HOUSE	1984	2033	13,192	9,158	7.150%	No	No	9,158	
258	FY 2021	LOWER SNAKE F AND W	1983	2033	30,983	9,472	7.150%	No	No	9,472	
259	FY 2021	JOHN DAY	1995	2035	22	22	7.150%	No	No	22	
260	FY 2021	JOHN DAY	1995	2035	52	52	7.150%	No	No	52	
261	FY 2021	JOHN DAY	1995	2035	121	121	7.150%	No	No	121	
262	FY 2021	LOWER SNAKE F AND W	1985	2035	47,921	47,921	7.150%	No	No	47,921	
263	FY 2021	LOWER MONUMENTAL	1996	2036	264	264	7.150%	Yes	No	264	
264	FY 2021	LOWER SNAKE F AND W	1987	2037	72,536	72,536	7.150%	No	No	72,536	
265	FY 2021	LIBBY	1988	2038	18,043	14,781	7.150%	No	No	14,781	
266	FY 2021	LOWER SNAKE F AND W	1988	2038	805	805	7.150%	No	No	805	
267	FY 2021	LITTLE GOOSE	1995	2040	17	17	7.150%	No	No	17	
268	FY 2021	LITTLE GOOSE	1995	2040	450	450	7.150%	No	No	450	
269	FY 2021	LITTLE GOOSE	1995	2040	733	733	7.150%	Yes	No	733	
270	FY 2021	LOWER SNAKE F AND W	1990	2040	1,557	1,557	7.150%	No	No	1,557	
271	FY 2021	ICE HARBOR	1996	2041	371	371	7.150%	Yes	No	371	
272	FY 2021	LOWER SNAKE F AND W	1991	2041	4,411	4,411	7.150%	No	No	4,411	
273	FY 2021	LOWER SNAKE F AND W	1993	2043	71,632	71,632	7.150%	No	No	71,632	
274	FY 2021	BONNEVILLE - 2ND POWER HOUSE	1994	2044	5,700	5,700	7.150%	No	No	5,700	
275	FY 2021	CHIEF JOSEPH	1994	2044	4,280	4,017	7.150%	No	No	4,017	
276	FY 2021	COLUMBIA BASIN - 3RD PWR HOUSE	1994	2044	12,631	12,631	7.150%	No	No	12,631	
277	FY 2021	LOWER SNAKE F AND W	1994	2044	4,722	4,722	7.150%	No	No	4,722	
278	FY 2021	BONNEVILLE - 2ND POWER HOUSE	1995	2045	3,791	3,791	7.150%	No	No	3,791	
279	FY 2021	CHIEF JOSEPH	1995	2045	147	147	7.150%	No	No	147	

Table 13: Application of Amortization FY 2011
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	A	B	C	D	E	F	G	H	I	J	K
1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
280	FY 2021	CHIEF JOSEPH	1995	2045	562	562	7.150%	No	No	562	
281	FY 2021	CHIEF JOSEPH	1995	2045	712	712	7.150%	Yes	No	712	
282	FY 2021	CHIEF JOSEPH	1995	2045	784	784	7.150%	No	No	784	
283	FY 2021	BONNEVILLE	1995	2045	243	243	7.150%	No	No	243	
284	FY 2021	BONNEVILLE	1995	2045	410	410	7.150%	Yes	No	410	
285	FY 2021	BONNEVILLE	1995	2045	440	440	7.150%	Yes	No	440	
286	FY 2021	COLUMBIA BASIN	1995	2045	287	287	7.150%	Yes	No	287	
287	FY 2021	COLUMBIA BASIN	1995	2045	2,511	2,453	7.150%	No	No	2,453	
288	FY 2021	DETROIT-BIG CLIFF	1995	2045	38	38	7.150%	No	No	38	
289	FY 2021	DWORSHAK	1995	2045	1,162	1,162	7.150%	No	No	1,162	
290	FY 2021	COLUMBIA RIVER FISH MITIGATION	1995	2045	43,343	39,282	7.150%	No	No	39,282	
291	FY 2021	HUNGRY HORSE	1995	2045	6,190	6,190	7.150%	No	No	6,190	
292	FY 2021	JOHN DAY	1995	2045	37	37	7.150%	No	No	37	
293	FY 2021	JOHN DAY	1995	2045	608	608	7.150%	No	No	608	
294	FY 2021	JOHN DAY	1995	2045	7,653	7,653	7.150%	Yes	No	7,653	
295	FY 2021	LOOKOUT POINT-DEXTER	1995	2045	80	39	7.150%	No	No	39	
296	FY 2021	LOOKOUT POINT-DEXTER	1995	2045	33	33	7.150%	No	No	33	
297	FY 2021	LOST CREEK	1995	2045	94	94	7.150%	No	No	94	
298	FY 2021	LOWER MONUMENTAL	1995	2045	41	41	7.150%	No	No	41	
299	FY 2021	LOWER MONUMENTAL	1995	2045	99	99	7.150%	No	No	99	
300	FY 2021	LOWER MONUMENTAL	1995	2045	624	624	7.150%	No	No	624	
301	FY 2021	LOWER MONUMENTAL	1995	2045	1,122	1,122	7.150%	Yes	No	1,122	
302	FY 2021	MCNARY	1995	2045	16	16	7.150%	No	No	16	
303	FY 2021	ALBENI FALLS	1995	2045	443	443	7.150%	No	No	443	
304	FY 2021	ALBENI FALLS	1995	2045	531	531	7.150%	No	No	531	
305	FY 2021	ALBENI FALLS	1995	2045	1,105	1,105	7.150%	No	No	1,105	
306	FY 2021	BOISE	1996	2046	442	442	7.150%	No	No	442	
307	FY 2021	BOISE	1996	2046	656	656	7.150%	No	No	656	
308	FY 2021	BONNEVILLE - 2ND POWER HOUSE	1996	2046	376	376	7.150%	No	No	376	
309	FY 2021	CHIEF JOSEPH	1996	2046	3	3	7.150%	Yes	No	3	
310	FY 2021	CHIEF JOSEPH	1996	2046	4	4	7.150%	Yes	No	4	
311	FY 2021	CHIEF JOSEPH	1996	2046	355	355	7.150%	No	No	355	
312	FY 2021	CHIEF JOSEPH	1996	2046	729	729	7.150%	No	No	729	
313	FY 2021	BONNEVILLE	1996	2046	18	18	7.150%	No	No	18	
314	FY 2021	BONNEVILLE	1996	2046	18	18	7.150%	No	No	18	
315	FY 2021	BONNEVILLE	1996	2046	80	80	7.150%	No	No	80	
316	FY 2021	BONNEVILLE	1996	2046	109	109	7.150%	No	No	109	
317	FY 2021	BONNEVILLE	1996	2046	142	142	7.150%	No	No	142	
318	FY 2021	BONNEVILLE	1996	2046	223	223	7.150%	No	No	223	
319	FY 2021	BONNEVILLE	1996	2046	751	751	7.150%	No	No	751	
320	FY 2021	BONNEVILLE	1996	2046	1,322	1,322	7.150%	Yes	No	1,322	
321	FY 2021	COLUMBIA BASIN	1996	2046	426	426	7.150%	No	No	426	
322	FY 2021	COLUMBIA BASIN	1996	2046	368	368	7.150%	No	No	368	
323	FY 2021	GREEN PETER-FOSTER	1996	2046	26	26	7.150%	No	No	26	
324	FY 2021	DWORSHAK	1996	2046	3	3	7.150%	Yes	No	3	
325	FY 2021	DWORSHAK	1996	2046	4	4	7.150%	Yes	No	4	
326	FY 2021	DWORSHAK	1996	2046	46	46	7.150%	No	No	46	
327	FY 2021	COLUMBIA RIVER FISH MITIGATION	1996	2046	2,431	2,431	7.150%	No	No	2,431	
328	FY 2021	HILLS CREEK	1996	2046	28	28	7.150%	No	No	28	
329	FY 2021	HUNGRY HORSE	1996	2046	15	15	7.150%	No	No	15	
330	FY 2021	HUNGRY HORSE	1996	2046	2	2	7.150%	No	No	2	
331	FY 2021	LITTLE GOOSE	1996	2046	10	10	7.150%	No	No	10	
332	FY 2021	LITTLE GOOSE	1996	2046	10	10	7.150%	No	No	10	
333	FY 2021	LITTLE GOOSE	1996	2046	211	211	7.150%	No	No	211	
334	FY 2021	LITTLE GOOSE	1996	2046	241	241	7.150%	No	No	241	
335	FY 2021	LITTLE GOOSE	1996	2046	520	520	7.150%	Yes	No	520	
336	FY 2021	LITTLE GOOSE	1996	2046	3,909	3,909	7.150%	Yes	No	3,909	
337	FY 2021	LOST CREEK	1996	2046	24	24	7.150%	No	No	24	
338	FY 2021	LOWER GRANITE	1996	2046	9	9	7.150%	Yes	No	9	
339	FY 2021	LOWER GRANITE	1996	2046	625	625	7.150%	No	No	625	
340	FY 2021	LOWER MONUMENTAL	1996	2046	10	10	7.150%	No	No	10	
341	FY 2021	LOWER SNAKE F AND W	1996	2046	12,085	12,085	7.150%	No	No	12,085	
342	FY 2021	MCNARY	1996	2046	619	619	7.150%	No	No	619	
343	FY 2021	THE DALLES	1996	2046	1,991	1,991	7.150%	No	No	1,991	
344	FY 2021	BOISE	1997	2047	2,272	2,266	7.150%	No	No	2,266	
345	FY 2021	CHIEF JOSEPH	1997	2047	657	657	7.150%	No	No	657	
346	FY 2021	BONNEVILLE	1997	2047	161	161	7.150%	No	No	161	
347	FY 2021	COUGAR	1997	2047	26	26	7.150%	No	No	26	
348	FY 2021	COLUMBIA BASIN	1997	2047	3,393	3,393	7.150%	No	No	3,393	
349	FY 2021	DWORSHAK	1997	2047	7,588	7,588	7.150%	No	No	7,588	
350	FY 2021	HUNGRY HORSE	1997	2047	111	111	7.150%	No	No	111	
351	FY 2021	ICE HARBOR	1997	2047	67	67	7.150%	No	No	67	
352	FY 2021	JOHN DAY	1997	2047	179	179	7.150%	No	No	179	
353	FY 2021	LIBBY	1997	2047	660	660	7.150%	No	No	660	
354	FY 2021	LITTLE GOOSE	1997	2047	1	1	7.150%	No	No	1	
355	FY 2021	LOWER GRANITE	1997	2047	677	677	7.150%	No	No	677	
356	FY 2021	LOWER SNAKE F AND W	1997	2047	2,173	2,173	7.150%	No	No	2,173	
357	FY 2021	MINIDOKA	1997	2047	50,911	50,911	7.150%	No	No	50,911	
358	FY 2021	ALBENI FALLS	1997	2047	431	431	7.150%	No	No	431	
359	FY 2021	ALBENI FALLS	2011	2056	120,494	120,494	6.780%	Yes	No	98,358	
360	**Subtotal**		-	-	**$675,974**	**$642,738**	-	**Yes**	**No**	**$620,602**	
361											
362	FY 2022	ALBENI FALLS	2011	2056	120,494	22,136	6.780%	Yes	No	22,136	
363	FY 2022	ALBENI FALLS	2012	2057	112,517	112,517	6.780%	Yes	No	112,517	
364	FY 2022	ALBENI FALLS	2013	2058	105,066	105,066	6.780%	Yes	No	105,066	
365	FY 2022	ALBENI FALLS	2014	2059	105,449	105,449	6.780%	Yes	No	105,449	
366	FY 2022	ALBENI FALLS	2015	2060	105,852	105,852	6.780%	Yes	No	105,852	
367	FY 2022	ALBENI FALLS	2016	2061	106,251	106,251	6.780%	Yes	No	106,251	
368	FY 2022	ALBENI FALLS	2017	2062	106,715	106,715	6.780%	Yes	No	97,717	
369	**Subtotal**		-	-	**$762,344**	**$663,986**	-	**Yes**	**No**	**$654,989**	
370											
371	FY 2023	DWORSHAK	1973	2023	138,443	-0	7.190%	No	No	-0	
372	FY 2023	BUREAU DIRECT FUND	2011	2056	170,850	170,850	6.930%	No	No	41,397	

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1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
373	FY 2023	ALBENI FALLS	2017	2062	106,715	8,998	6.780%	Yes	No	8,998	
374	FY 2023	ALBENI FALLS	2018	2063	107,240	107,240	6.780%	Yes	No	107,240	
375	FY 2023	ALBENI FALLS	2019	2064	107,824	107,824	6.780%	Yes	No	107,824	
376	FY 2023	ALBENI FALLS	2020	2065	108,460	108,460	6.780%	Yes	No	108,460	
377	FY 2023	ALBENI FALLS	2021	2066	109,147	109,147	6.780%	Yes	No	109,147	
378	FY 2023	ALBENI FALLS	2022	2067	109,881	109,881	6.780%	Yes	No	109,881	
379	FY 2023	ALBENI FALLS	2023	2068	97,810	97,810	6.780%	Yes	No	97,810	
380	**Subtotal**		-	-	**$1,056,370**	**$820,210**	-	**Yes**	**No**	**$690,757**	
381											
382	FY 2024	FISH, WILDLIFE	2009	2024	50,000	50,000	4.720%	No	No	50,000	
383	FY 2024	FISH, WILDLIFE	2011	2026	60,000	60,000	6.220%	No	No	24,844	
384	FY 2024	BPA PROGRAM	2010	2045	13,871	13,871	6.790%	No	No	13,871	
385	FY 2024	BPA PROGRAM	2011	2046	14,950	14,950	6.930%	No	No	14,950	
386	FY 2024	BONNEVILLE	2000	2050	24,446	24,446	6.125%	No	No	24,446	
387	FY 2024	COLUMBIA RIVER FISH MITIGATION	2000	2050	47,006	47,006	6.125%	No	No	47,006	
388	FY 2024	HILLS CREEK	2000	2050	2,630	2,630	6.125%	No	No	2,630	
389	FY 2024	ICE HARBOR	2000	2050	548	548	6.125%	No	No	548	
390	FY 2024	JOHN DAY	2000	2050	2,761	2,761	6.125%	No	No	2,761	
391	FY 2024	LOOKOUT POINT-DEXTER	2000	2050	5,098	5,098	6.125%	No	No	5,098	
392	FY 2024	LOWER SNAKE F AND W	2000	2050	1,529	1,529	6.125%	No	No	1,529	
393	FY 2024	THE DALLES	2000	2050	2,588	2,588	6.125%	No	No	2,588	
394	FY 2024	CHIEF JOSEPH	2001	2051	345	345	5.875%	No	No	345	
395	FY 2024	BONNEVILLE	2001	2051	2,530	2,530	5.875%	No	No	2,530	
396	FY 2024	COLUMBIA BASIN	2001	2051	69,226	69,226	5.875%	No	No	69,226	
397	FY 2024	GREEN PETER-FOSTER	2001	2051	200	200	5.875%	No	No	200	
398	FY 2024	DETROIT-BIG CLIFF	2001	2051	282	282	5.875%	No	No	282	
399	FY 2024	COLUMBIA RIVER FISH MITIGATION	2001	2051	6,168	6,168	5.875%	No	No	6,168	
400	FY 2024	HILLS CREEK	2001	2051	8	8	5.875%	No	No	8	
401	FY 2024	HUNGRY HORSE	2001	2051	552	552	5.875%	No	No	552	
402	FY 2024	ICE HARBOR	2001	2051	764	764	5.875%	No	No	764	
403	FY 2024	JOHN DAY	2001	2051	619	619	5.875%	No	No	619	
404	FY 2024	LIBBY	2001	2051	5,562	5,562	5.875%	No	No	5,562	
405	FY 2024	LITTLE GOOSE	2001	2051	4,608	4,608	5.875%	No	No	4,608	
406	FY 2024	LOST CREEK	2001	2051	154	154	5.875%	No	No	154	
407	FY 2024	LOWER GRANITE	2001	2051	2,025	2,025	5.875%	No	No	2,025	
408	FY 2024	LOWER MONUMENTAL	2001	2051	3,301	3,301	5.875%	No	No	3,301	
409	FY 2024	LOWER SNAKE F AND W	2001	2051	325	325	5.875%	No	No	325	
410	FY 2024	MCNARY	2001	2051	1,046	1,046	5.875%	No	No	1,046	
411	FY 2024	MINIDOKA	2001	2051	61	49	5.875%	No	No	49	
412	FY 2024	UNASSIGNED BOND	2001	2051	11,145	11,145	5.875%	No	No	11,145	
413	FY 2024	YAKIMA-ROZA	2001	2051	15	14	5.875%	No	No	14	
414	FY 2024	BUREAU DIRECT FUND	2010	2055	157,850	157,850	6.790%	No	No	157,850	
415	FY 2024	BUREAU DIRECT FUND	2011	2056	170,850	129,453	6.930%	No	No	129,453	
416	FY 2024	ALBENI FALLS	2024	2069	87,212	87,212	6.780%	Yes	No	87,212	
417	**Subtotal**		-	-	**$750,275**	**$708,865**	-	**Yes**	**No**	**$673,710**	
418											
419	FY 2025	LIBBY	1975	2025	54,644	-0	7.160%	No	No	-0	
420	FY 2025	FISH, WILDLIFE	2010	2025	70,000	70,000	4.930%	No	No	70,000	
421	FY 2025	FISH, WILDLIFE	2011	2026	60,000	35,156	6.220%	No	No	35,156	
422	FY 2025	BONNEVILLE	1999	2049	19,368	19,368	5.375%	No	No	19,368	
423	FY 2025	DWORSHAK	1999	2049	630	630	5.375%	No	No	630	
424	FY 2025	COLUMBIA RIVER FISH MITIGATION	1999	2049	14,115	14,115	5.375%	No	No	14,115	
425	FY 2025	ICE HARBOR	1999	2049	5,516	5,516	5.375%	No	No	5,516	
426	FY 2025	JOHN DAY	1999	2049	3,510	3,510	5.375%	No	No	3,510	
427	FY 2025	LOWER GRANITE	1999	2049	856	856	5.375%	No	No	856	
428	FY 2025	LOWER SNAKE F AND W	1999	2049	7	7	5.375%	No	No	7	
429	FY 2025	CHIEF JOSEPH	2002	2052	2	2	5.500%	No	No	2	
430	FY 2025	BONNEVILLE	2002	2052	448	448	5.500%	No	No	448	
431	FY 2025	DETROIT-BIG CLIFF	2002	2052	18	18	5.500%	No	No	18	
432	FY 2025	DWORSHAK	2002	2052	199	199	5.500%	No	No	199	
433	FY 2025	COLUMBIA RIVER FISH MITIGATION	2002	2052	8,797	8,797	5.500%	No	No	8,797	
434	FY 2025	HILLS CREEK	2002	2052	2	2	5.500%	No	No	2	
435	FY 2025	ICE HARBOR	2002	2052	1,014	1,014	5.500%	No	No	1,014	
436	FY 2025	LITTLE GOOSE	2002	2052	27	27	5.500%	No	No	27	
437	FY 2025	LOWER GRANITE	2002	2052	1,275	1,275	5.500%	No	No	1,275	
438	FY 2025	LOWER MONUMENTAL	2002	2052	29	29	5.500%	No	No	29	
439	FY 2025	LOWER SNAKE F AND W	2002	2052	890	890	5.500%	No	No	890	
440	FY 2025	THE DALLES	2002	2052	1,226	1,226	5.500%	No	No	1,226	
441	FY 2025	MCNARY	2003	2053	97	97	5.750%	No	No	97	
442	FY 2025	BONNEVILLE	2004	2054	26,741	26,741	5.375%	No	No	26,741	
443	FY 2025	COUGAR	2004	2054	15,748	15,748	5.375%	No	No	15,748	
444	FY 2025	COLUMBIA RIVER FISH MITIGATION	2004	2054	60,581	60,581	5.375%	No	No	60,581	
445	FY 2025	ICE HARBOR	2004	2054	3,321	3,321	5.375%	No	No	3,321	
446	FY 2025	JOHN DAY	2004	2054	2,830	2,830	5.375%	No	No	2,830	
447	FY 2025	LITTLE GOOSE	2004	2054	67	67	5.375%	No	No	68	
448	FY 2025	LOWER MONUMENTAL	2004	2054	3,423	3,423	5.375%	No	No	3,423	
449	FY 2025	LOWER SNAKE F AND W	2004	2054	230	230	5.375%	No	No	230	
450	FY 2025	MCNARY	2004	2054	6,138	6,138	5.375%	No	No	6,138	
451	FY 2025	THE DALLES	2004	2054	182	182	5.375%	No	No	182	
452	FY 2025	BUREAU DIRECT FUND	2009	2054	133,238	133,238	5.350%	No	No	69,102	
453	FY 2025	COLUMBIA RIVER FISH MITIGATION	2010	2060	88,000	88,000	5.290%	No	No	88,000	
454	FY 2025	COLUMBIA RIVER FISH MITIGATION	2011	2061	96,000	96,000	5.730%	No	No	96,000	
455	FY 2025	ALBENI FALLS	2025	2070	77,863	77,863	6.780%	Yes	No	77,863	
456	**Subtotal**		-	-	**$757,029**	**$677,541**	-	**Yes**	**No**	**$613,405**	
457											
458	FY 2026	COLUMBIA BASIN	1996	2026	72	0	7.150%	No	No	0	
459	FY 2026	BPA PROGRAM	2009	2044	16,500	12,714	5.350%	No	No	12,714	
460	FY 2026	CHIEF JOSEPH	2003	2053	992	992	5.125%	No	No	992	
461	FY 2026	BONNEVILLE	2003	2053	4,581	4,581	5.125%	No	No	4,581	
462	FY 2026	DETROIT-BIG CLIFF	2003	2053	223	223	5.125%	No	No	223	
463	FY 2026	DWORSHAK	2003	2053	761	761	5.125%	No	No	761	
464	FY 2026	COLUMBIA RIVER FISH MITIGATION	2003	2053	68,440	68,440	5.125%	No	No	68,440	
465	FY 2026	ICE HARBOR	2003	2053	50	50	5.125%	No	No	50	

Table 13: Application of Amortization FY 2011
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
466	FY 2026	LITTLE GOOSE	2003	2053	146	146	5.125%	No	No	146	
467	FY 2026	LOOKOUT POINT-DEXTER	2003	2053	135	135	5.125%	No	No	135	
468	FY 2026	LOWER GRANITE	2003	2053	42	42	5.125%	No	No	42	
469	FY 2026	LOWER MONUMENTAL	2003	2053	22	22	5.125%	No	No	22	
470	FY 2026	LOWER SNAKE F AND W	2003	2053	98	98	5.125%	No	No	98	
471	FY 2026	BUREAU DIRECT FUND	2009	2054	133,238	64,136	5.350%	No	No	64,136	
472	FY 2026	BOISE	2005	2055	903	903	5.125%	No	No	903	
473	FY 2026	BONNEVILLE	2005	2055	19,725	19,725	5.125%	No	No	19,725	
474	FY 2026	COUGAR	2005	2055	35,317	35,317	5.125%	No	No	35,317	
475	FY 2026	COLUMBIA BASIN	2005	2055	10,963	10,963	5.125%	No	No	10,963	
476	FY 2026	DETROIT-BIG CLIFF	2005	2055	1,031	1,031	5.125%	No	No	1,031	
477	FY 2026	DWORSHAK	2005	2055	713	713	5.125%	No	No	713	
478	FY 2026	COLUMBIA RIVER FISH MITIGATION	2005	2055	52,039	52,039	5.125%	No	No	52,039	
479	FY 2026	HILLS CREEK	2005	2055	46	46	5.125%	No	No	46	
480	FY 2026	HUNGRY HORSE	2005	2055	2,951	2,951	5.125%	No	No	2,951	
481	FY 2026	JOHN DAY	2005	2055	2,827	2,827	5.125%	No	No	2,828	
482	FY 2026	LOOKOUT POINT-DEXTER	2005	2055	7,355	7,355	5.125%	No	No	7,355	
483	FY 2026	LOWER GRANITE	2005	2055	393	393	5.125%	No	No	393	
484	FY 2026	LOWER MONUMENTAL	2005	2055	527	527	5.125%	No	No	527	
485	FY 2026	LOWER SNAKE F AND W	2005	2055	4	4	5.125%	No	No	4	
486	FY 2026	MCNARY	2005	2055	550	550	5.125%	No	No	550	
487	FY 2026	ALBENI FALLS	2005	2055	481	481	5.125%	No	No	481	
488	FY 2026	YAKIMA-CHANDLER	2005	2055	833	833	5.125%	No	No	833	
489	FY 2026	THE DALLES	2005	2055	36,019	36,019	5.125%	No	No	36,019	
490	FY 2026	COLUMBIA RIVER FISH MITIGATION	2006	2056	366,395	366,395	4.500%	No	No	176,128	
491	FY 2026	JOHN DAY	2006	2056	601	601	4.500%	No	No	601	
492	FY 2026	LOWER MONUMENTAL	2006	2056	285	285	4.500%	No	No	285	
493	FY 2026	LOWER SNAKE F AND W	2006	2056	379	379	4.500%	No	No	379	
494	FY 2026	MCNARY	2006	2056	8,169	4,080	4.500%	No	No	4,080	
495	FY 2026	THE DALLES	2006	2056	2,030	2,030	4.500%	No	No	2,030	
496	FY 2026	BOISE	2007	2057	76	76	5.000%	No	No	76	
497	FY 2026	BONNEVILLE	2007	2057	1,124	1,124	5.000%	No	No	1,124	
498	FY 2026	COUGAR	2007	2057	521	521	5.000%	No	No	521	
499	FY 2026	COLUMBIA BASIN	2007	2057	929	929	5.000%	No	No	929	
500	FY 2026	COLUMBIA RIVER FISH MITIGATION	2007	2057	53,525	53,525	5.000%	No	No	53,525	
501	FY 2026	HUNGRY HORSE	2007	2057	294	294	5.000%	No	No	294	
502	FY 2026	JOHN DAY	2007	2057	233	233	5.000%	No	No	233	
503	FY 2026	LOOKOUT POINT-DEXTER	2007	2057	572	572	5.000%	No	No	572	
504	FY 2026	MINIDOKA	2007	2057	17	17	5.000%	No	No	17	
505	FY 2026	THE DALLES	2007	2057	140	140	5.000%	No	No	140	
506	FY 2026	ALBENI FALLS	2026	2071	69,622	69,622	6.780%	Yes	No	69,622	
507	**Subtotal**		-	-	**$902,887**	**$825,838**	-	**Yes**	**No**	**$635,570**	
508											
509	FY 2027	BOISE	2006	2056	15	15	4.500%	No	No	15	
510	FY 2027	BONNEVILLE	2006	2056	4,203	2,628	4.500%	No	No	2,628	
511	FY 2027	COUGAR	2006	2056	474	474	4.500%	No	No	474	
512	FY 2027	COLUMBIA BASIN	2006	2056	1,987	1,987	4.500%	No	No	1,987	
513	FY 2027	DWORSHAK	2006	2056	73	73	4.500%	No	No	73	
514	FY 2027	COLUMBIA RIVER FISH MITIGATION	2006	2056	366,395	190,267	4.500%	No	No	190,267	
515	FY 2027	BOISE	2008	2058	69	69	4.375%	No	No	70	
516	FY 2027	CHIEF JOSEPH	2008	2058	3,600	3,600	4.375%	No	No	3,600	
517	FY 2027	BONNEVILLE	2008	2058	14,609	14,609	4.375%	No	No	14,609	
518	FY 2027	COLUMBIA BASIN	2008	2058	837	837	4.375%	No	No	837	
519	FY 2027	DWORSHAK	2008	2058	22	22	4.375%	No	No	22	
520	FY 2027	COLUMBIA RIVER FISH MITIGATION	2008	2058	37,277	37,277	4.375%	No	No	37,277	
521	FY 2027	HUNGRY HORSE	2008	2058	76	76	4.375%	No	No	76	
522	FY 2027	ICE HARBOR	2008	2058	14	14	4.375%	No	No	14	
523	FY 2027	LIBBY	2008	2058	1,652	1,652	4.375%	No	No	1,652	
524	FY 2027	LITTLE GOOSE	2008	2058	14	14	4.375%	No	No	14	
525	FY 2027	LOWER GRANITE	2008	2058	1	1	4.375%	No	No	1	
526	FY 2027	LOWER MONUMENTAL	2008	2058	42	42	4.375%	No	No	42	
527	FY 2027	MCNARY	2008	2058	331	331	4.375%	No	No	331	
528	FY 2027	MINIDOKA	2008	2058	0	0	4.375%	No	No	0	
529	FY 2027	COLUMBIA RIVER FISH MITIGATION	2009	2060	110,000	110,000	4.380%	No	No	110,000	
530	FY 2027	ALBENI FALLS	2027	2072	62,363	62,363	6.780%	Yes	No	62,363	
531	**Subtotal**		-	-	**$604,055**	**$426,353**	-	**Yes**	**No**	**$426,353**	
532											
533	FY 2028	ALBENI FALLS	2028	2073	55,898	55,898	6.780%	Yes	No	55,898	
534	**Subtotal**		-	-	**$55,898**	**$55,898**	-	**Yes**	**No**	**$55,898**	
535											
536	FY 2029	ALBENI FALLS	2029	2074	50,186	50,186	6.780%	Yes	No	50,186	
537	**Subtotal**		-	-	**$50,186**	**$50,186**	-	**Yes**	**No**	**$50,186**	
538											
539	FY 2030	ALBENI FALLS	2030	2075	45,188	45,188	6.780%	Yes	No	45,188	
540	**Subtotal**		-	-	**$45,188**	**$45,188**	-	**Yes**	**No**	**$45,188**	
541											
542	FY 2031	BUREAU DIRECT FUND	2007	2031	30,000	30,000	5.730%	No	Yes	30,000	
543	FY 2031	ALBENI FALLS	2031	2076	40,741	40,741	6.780%	Yes	No	40,741	
544	**Subtotal**		-	-	**$70,741**	**$70,741**	-	**Yes**	**Yes**	**$70,741**	
545											
546	FY 2032	ALBENI FALLS	2032	2077	36,816	36,816	6.780%	Yes	No	36,816	
547	**Subtotal**		-	-	**$36,816**	**$36,816**	-	**Yes**	**No**	**$36,816**	
548											
549	FY 2033	LOWER SNAKE F AND W	1983	2033	30,983	0	7.150%	No	No	0	
550	FY 2033	BPA PROGRAM	2008	2033	10,000	10,000	6.500%	No	Yes	10,000	
551	FY 2033	BPA PROGRAM	2008	2033	10,000	10,000	6.500%	No	Yes	10,000	
552	FY 2033	ALBENI FALLS	2033	2078	52,599	52,599	6.780%	Yes	No	52,599	
553	**Subtotal**		-	-	**$103,582**	**$72,599**	-	**Yes**	**Yes**	**$72,599**	
554											
555	FY 2034	ALBENI FALLS	2034	2079	53,078	53,078	6.780%	Yes	No	53,078	
556	**Subtotal**		-	-	**$53,078**	**$53,078**	-	**Yes**	**No**	**$53,078**	
557											
558	FY 2035	ALBENI FALLS	2035	2080	53,600	53,600	6.780%	Yes	No	53,600	

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	A	B	C	D	E	F	G	H	I	J	K
1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
559	**Subtotal**		-	-	**$53,600**	**$53,600**	-	**Yes**	**No**	**$53,600**	
560											
561	FY 2036	BPA PROGRAM	2006	2036	9,681	9,681	5.970%	No	Yes	9,681	
562	FY 2036	ALBENI FALLS	2036	2081	54,107	54,107	6.780%	Yes	No	54,107	
563	**Subtotal**		-	-	**$63,788**	**$63,788**	-	**Yes**	**Yes**	**$63,788**	
564											
565	FY 2037	ALBENI FALLS	2037	2082	54,656	54,656	6.780%	Yes	No	54,656	
566	**Subtotal**		-	-	**$54,656**	**$54,656**	-	**Yes**	**No**	**$54,656**	
567											
568	FY 2038	ALBENI FALLS	2038	2083	55,244	55,244	6.780%	Yes	No	55,244	
569	**Subtotal**		-	-	**$55,244**	**$55,244**	-	**Yes**	**No**	**$55,244**	
570											
571	FY 2039	BUREAU DIRECT FUND	2006	2039	45,000	45,000	5.520%	No	Yes	45,000	
572	FY 2039	ALBENI FALLS	2039	2084	55,872	55,872	6.780%	Yes	No	55,872	
573	**Subtotal**		-	-	**$100,872**	**$100,872**	-	**Yes**	**Yes**	**$100,872**	
574											
575	FY 2040	ALBENI FALLS	2040	2085	56,480	56,480	6.780%	Yes	No	56,480	
576	**Subtotal**		-	-	**$56,480**	**$56,480**	-	**Yes**	**No**	**$56,480**	
577											
578	FY 2041	BUREAU DIRECT FUND	2008	2041	30,000	30,000	6.840%	No	Yes	30,000	
579	FY 2041	ALBENI FALLS	2041	2086	57,125	57,125	6.780%	Yes	No	57,125	
580	**Subtotal**		-	-	**$87,125**	**$87,125**	-	**Yes**	**Yes**	**$87,125**	
581											
582	FY 2042	BUREAU DIRECT FUND	2008	2042	35,000	35,000	6.880%	No	Yes	35,000	
583	FY 2042	BUREAU DIRECT FUND	2008	2042	35,000	35,000	6.880%	No	Yes	35,000	
584	FY 2042	BUREAU DIRECT FUND	2008	2042	35,000	35,000	6.720%	No	Yes	35,000	
585	FY 2042	ALBENI FALLS	2042	2087	57,806	57,806	6.780%	Yes	No	57,806	
586	**Subtotal**		-	-	**$162,806**	**$162,806**	-	**Yes**	**Yes**	**$162,806**	
587											
588	FY 2043	BUREAU DIRECT FUND	2007	2043	35,000	35,000	6.160%	No	Yes	35,000	
589	FY 2043	BUREAU DIRECT FUND	2006	2043	15,000	15,000	5.520%	No	Yes	15,000	
590	FY 2043	ALBENI FALLS	2043	2088	54,460	54,460	6.780%	Yes	No	54,460	
591	**Subtotal**		-	-	**$104,460**	**$104,460**	-	**Yes**	**Yes**	**$104,460**	
592											
593	FY 2044	BUREAU DIRECT FUND	2008	2044	20,000	20,000	6.720%	No	Yes	20,000	
594	FY 2044	BUREAU DIRECT FUND	2008	2044	35,000	35,000	6.720%	No	Yes	35,000	
595	FY 2044	BUREAU DIRECT FUND	2007	2044	30,000	30,000	6.160%	No	Yes	30,000	
596	FY 2044	ALBENI FALLS	2044	2089	51,311	51,311	6.780%	Yes	No	51,311	
597	**Subtotal**		-	-	**$136,311**	**$136,311**	-	**Yes**	**Yes**	**$136,311**	
598											
599	FY 2045	COLUMBIA BASIN	1995	2045	287	0	7.150%	Yes	No	0	
600	FY 2045	BUREAU DIRECT FUND	2008	2045	25,000	25,000	6.720%	No	Yes	25,000	
601	FY 2045	ALBENI FALLS	2045	2090	48,402	48,402	6.780%	Yes	No	48,402	
602	**Subtotal**		-	-	**$73,689**	**$73,402**	-	**Yes**	**Yes**	**$73,402**	
603											
604	FY 2046	BOISE	1996	2046	442	0	7.150%	No	No	0	
605	FY 2046	ALBENI FALLS	2046	2091	45,674	45,674	6.780%	Yes	No	45,674	
606	**Subtotal**		-	-	**$46,116**	**$45,674**	-	**Yes**	**No**	**$45,674**	
607											
608	FY 2047	BOISE	1997	2047	2,272	-0	7.150%	No	No	-0	
609	FY 2047	HUNGRY HORSE	1997	2047	111	0	7.150%	No	No	0	
610	FY 2047	MINIDOKA	1997	2047	50,911	0	7.150%	No	No	0	
611	FY 2047	ALBENI FALLS	1997	2047	431	-0	7.150%	No	No	-0	
612	FY 2047	ALBENI FALLS	2047	2092	43,118	43,118	6.780%	Yes	No	43,118	
613	**Subtotal**		-	-	**$96,843**	**$43,118**	-	**Yes**	**No**	**$43,118**	
614											
615	FY 2048	ALBENI FALLS	2048	2093	40,728	40,728	6.780%	Yes	No	40,728	
616	**Subtotal**		-	-	**$40,728**	**$40,728**	-	**Yes**	**No**	**$40,728**	
617											
618	FY 2049	BONNEVILLE	1999	2049	19,368	0	5.375%	No	No	0	
619	FY 2049	DWORSHAK	1999	2049	630	-0	5.375%	No	No	-0	
620	FY 2049	COLUMBIA RIVER FISH MITIGATION	1999	2049	14,115	0	5.375%	No	No	0	
621	FY 2049	ICE HARBOR	1999	2049	5,516	-0	5.375%	No	No	-0	
622	FY 2049	JOHN DAY	1999	2049	3,510	0	5.375%	No	No	0	
623	FY 2049	LOWER GRANITE	1999	2049	856	-0	5.375%	No	No	-0	
624	FY 2049	ALBENI FALLS	2049	2094	36,747	36,747	6.780%	Yes	No	36,747	
625	**Subtotal**		-	-	**$80,740**	**$36,747**	-	**Yes**	**No**	**$36,747**	
626											
627	FY 2050	BONNEVILLE	2000	2050	24,446	0	6.125%	No	No	0	
628	FY 2050	COLUMBIA RIVER FISH MITIGATION	2000	2050	47,006	-0	6.125%	No	No	-0	
629	FY 2050	HILLS CREEK	2000	2050	2,630	0	6.125%	No	No	0	
630	FY 2050	ICE HARBOR	2000	2050	548	0	6.125%	No	No	0	
631	FY 2050	JOHN DAY	2000	2050	2,761	0	6.125%	No	No	0	
632	FY 2050	LOOKOUT POINT-DEXTER	2000	2050	5,098	0	6.125%	No	No	0	
633	FY 2050	THE DALLES	2000	2050	2,588	0	6.125%	No	No	0	
634	FY 2050	ALBENI FALLS	2050	2095	33,205	33,205	6.780%	Yes	No	33,205	
635	**Subtotal**		-	-	**$118,283**	**$33,205**	-	**Yes**	**No**	**$33,205**	
636											
637	FY 2051	CHIEF JOSEPH	2001	2051	345	0	5.875%	No	No	0	
638	FY 2051	BONNEVILLE	2001	2051	2,530	0	5.875%	No	No	0	
639	FY 2051	COLUMBIA BASIN	2001	2051	69,226	-0	5.875%	No	No	-0	
640	FY 2051	GREEN PETER-FOSTER	2001	2051	200	0	5.875%	No	No	0	
641	FY 2051	DETROIT-BIG CLIFF	2001	2051	282	0	5.875%	No	No	0	
642	FY 2051	COLUMBIA RIVER FISH MITIGATION	2001	2051	6,168	-0	5.875%	No	No	-0	
643	FY 2051	HILLS CREEK	2001	2051	8	-0	5.875%	No	No	-0	
644	FY 2051	HUNGRY HORSE	2001	2051	552	0	5.875%	No	No	0	
645	FY 2051	ICE HARBOR	2001	2051	764	0	5.875%	No	No	0	
646	FY 2051	JOHN DAY	2001	2051	619	-0	5.875%	No	No	-0	
647	FY 2051	LIBBY	2001	2051	5,562	-0	5.875%	No	No	-0	
648	FY 2051	LITTLE GOOSE	2001	2051	4,608	0	5.875%	No	No	0	
649	FY 2051	LOST CREEK	2001	2051	154	0	5.875%	No	No	0	
650	FY 2051	LOWER GRANITE	2001	2051	2,025	-0	5.875%	No	No	-0	
651	FY 2051	LOWER MONUMENTAL	2001	2051	3,301	0	5.875%	No	No	0	

($000s)

	A	B	C	D	E	F	G	H	I	J	K
1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
652	FY 2051	MCNARY	2001	2051	1,046	-0	5.875%	No	No	-0	
653	FY 2051	MINIDOKA	2001	2051	61	-0	5.875%	No	No	-0	
654	FY 2051	UNASSIGNED BOND	2001	2051	11,145	-0	5.875%	No	No	-0	
655	FY 2051	YAKIMA-ROZA	2001	2051	15	-0	5.875%	No	No	-0	
656	FY 2051	ALBENI FALLS	2051	2096	30,083	30,083	6.780%	Yes	No	30,083	
657	**Subtotal**		-	-	**$138,694**	**$30,083**	-	**Yes**	**No**	**$30,083**	
658											
659	FY 2052	CHIEF JOSEPH	2002	2052	2	-0	5.500%	No	No	-0	
660	FY 2052	BONNEVILLE	2002	2052	448	-0	5.500%	No	No	-0	
661	FY 2052	DETROIT-BIG CLIFF	2002	2052	18	0	5.500%	No	No	0	
662	FY 2052	DWORSHAK	2002	2052	199	0	5.500%	No	No	0	
663	FY 2052	HILLS CREEK	2002	2052	2	0	5.500%	No	No	0	
664	FY 2052	ICE HARBOR	2002	2052	1,014	-0	5.500%	No	No	-0	
665	FY 2052	LITTLE GOOSE	2002	2052	27	0	5.500%	No	No	0	
666	FY 2052	LOWER GRANITE	2002	2052	1,275	-0	5.500%	No	No	-0	
667	FY 2052	LOWER MONUMENTAL	2002	2052	29	0	5.500%	No	No	0	
668	FY 2052	THE DALLES	2002	2052	1,226	-0	5.500%	No	No	-0	
669	FY 2052	ALBENI FALLS	2052	2097	27,321	27,321	6.780%	Yes	No	27,321	
670	**Subtotal**		-	-	**$31,560**	**$27,321**	-	**Yes**	**No**	**$27,321**	
671											
672	FY 2053	MCNARY	2003	2053	97	-0	5.750%	No	No	-0	
673	FY 2053	BONNEVILLE	2003	2053	4,581	0	5.125%	No	No	0	
674	FY 2053	DETROIT-BIG CLIFF	2003	2053	223	0	5.125%	No	No	0	
675	FY 2053	DWORSHAK	2003	2053	761	-0	5.125%	No	No	-0	
676	FY 2053	COLUMBIA RIVER FISH MITIGATION	2003	2053	68,440	-0	5.125%	No	No	-0	
677	FY 2053	ICE HARBOR	2003	2053	50	0	5.125%	No	No	0	
678	FY 2053	LITTLE GOOSE	2003	2053	146	-0	5.125%	No	No	-0	
679	FY 2053	LOOKOUT POINT-DEXTER	2003	2053	135	0	5.125%	No	No	0	
680	FY 2053	LOWER MONUMENTAL	2003	2053	22	0	5.125%	No	No	0	
681	FY 2053	LOWER SNAKE F AND W	2003	2053	98	-0	5.125%	No	No	-0	
682	FY 2053	ALBENI FALLS	2053	2098	42,785	42,785	6.780%	Yes	No	42,785	
683	**Subtotal**		-	-	**$117,337**	**$42,785**	-	**Yes**	**No**	**$42,785**	
684											
685	FY 2054	BONNEVILLE	2004	2054	26,741	0	5.375%	No	No	0	
686	FY 2054	COUGAR	2004	2054	15,748	-0	5.375%	No	No	-0	
687	FY 2054	COLUMBIA RIVER FISH MITIGATION	2004	2054	60,581	-0	5.375%	No	No	-0	
688	FY 2054	ICE HARBOR	2004	2054	3,321	0	5.375%	No	No	0	
689	FY 2054	LITTLE GOOSE	2004	2054	67	-0	5.375%	No	No	-0	
690	FY 2054	LOWER MONUMENTAL	2004	2054	3,423	0	5.375%	No	No	0	
691	FY 2054	LOWER SNAKE F AND W	2004	2054	230	0	5.375%	No	No	0	
692	FY 2054	MCNARY	2004	2054	6,138	-0	5.375%	No	No	-0	
693	FY 2054	THE DALLES	2004	2054	182	0	5.375%	No	No	0	
694	FY 2054	BUREAU DIRECT FUND	2009	2054	133,238	-0	5.350%	No	No	-0	
695	FY 2054	ALBENI FALLS	2054	2099	43,358	43,358	6.780%	Yes	No	43,358	
696	**Subtotal**		-	-	**$293,027**	**$43,358**	-	**Yes**	**No**	**$43,358**	
697											
698	FY 2055	BOISE	2005	2055	903	-0	5.125%	No	No	-0	
699	FY 2055	BONNEVILLE	2005	2055	19,725	-0	5.125%	No	No	-0	
700	FY 2055	COUGAR	2005	2055	35,317	-0	5.125%	No	No	-0	
701	FY 2055	COLUMBIA BASIN	2005	2055	10,963	0	5.125%	No	No	0	
702	FY 2055	DETROIT-BIG CLIFF	2005	2055	1,031	-0	5.125%	No	No	-0	
703	FY 2055	DWORSHAK	2005	2055	713	-0	5.125%	No	No	-0	
704	FY 2055	COLUMBIA RIVER FISH MITIGATION	2005	2055	52,039	-0	5.125%	No	No	-0	
705	FY 2055	HILLS CREEK	2005	2055	46	-0	5.125%	No	No	-0	
706	FY 2055	HUNGRY HORSE	2005	2055	2,951	0	5.125%	No	No	0	
707	FY 2055	JOHN DAY	2005	2055	2,827	-0	5.125%	No	No	-0	
708	FY 2055	LOOKOUT POINT-DEXTER	2005	2055	7,355	-0	5.125%	No	No	-0	
709	FY 2055	LOWER SNAKE F AND W	2005	2055	4	-0	5.125%	No	No	-0	
710	FY 2055	MCNARY	2005	2055	550	0	5.125%	No	No	0	
711	FY 2055	ALBENI FALLS	2005	2055	481	-0	5.125%	No	No	-0	
712	FY 2055	YAKIMA-CHANDLER	2005	2055	833	0	5.125%	No	No	0	
713	FY 2055	THE DALLES	2005	2055	36,019	0	5.125%	No	No	0	
714	FY 2055	ALBENI FALLS	2055	2100	43,962	43,962	6.780%	Yes	No	43,962	
715	**Subtotal**		-	-	**$215,719**	**$43,962**	-	**Yes**	**No**	**$43,962**	
716											
717	FY 2056	BUREAU DIRECT FUND	2011	2056	170,850	-0	6.930%	No	No	-0	
718	FY 2056	ALBENI FALLS	2011	2056	120,494	-0	6.780%	Yes	No	-0	
719	FY 2056	BOISE	2006	2056	15	-0	4.500%	No	No	-0	
720	FY 2056	BONNEVILLE	2006	2056	4,203	-0	4.500%	No	No	-0	
721	FY 2056	COLUMBIA BASIN	2006	2056	1,987	0	4.500%	No	No	0	
722	FY 2056	COLUMBIA RIVER FISH MITIGATION	2006	2056	366,395	-0	4.500%	No	No	-0	
723	FY 2056	LOWER MONUMENTAL	2006	2056	285	-0	4.500%	No	No	-0	
724	FY 2056	LOWER SNAKE F AND W	2006	2056	379	0	4.500%	No	No	0	
725	FY 2056	THE DALLES	2006	2056	2,030	-0	4.500%	No	No	-0	
726	FY 2056	ALBENI FALLS	2056	2101	44,597	44,597	6.780%	Yes	No	44,597	
727	**Subtotal**		-	-	**$711,234**	**$44,597**	-	**Yes**	**No**	**$44,597**	
728											
729	FY 2057	BOISE	2007	2057	76	0	5.000%	No	No	0	
730	FY 2057	BONNEVILLE	2007	2057	1,124	-0	5.000%	No	No	-0	
731	FY 2057	COUGAR	2007	2057	521	0	5.000%	No	No	0	
732	FY 2057	COLUMBIA BASIN	2007	2057	929	0	5.000%	No	No	0	
733	FY 2057	COLUMBIA RIVER FISH MITIGATION	2007	2057	53,525	-0	5.000%	No	No	-0	
734	FY 2057	HUNGRY HORSE	2007	2057	294	0	5.000%	No	No	0	
735	FY 2057	JOHN DAY	2007	2057	233	-0	5.000%	No	No	-0	
736	FY 2057	LOOKOUT POINT-DEXTER	2007	2057	572	0	5.000%	No	No	0	
737	FY 2057	MINIDOKA	2007	2057	17	0	5.000%	No	No	0	
738	FY 2057	THE DALLES	2007	2057	140	-0	5.000%	No	No	-0	
739	FY 2057	ALBENI FALLS	2057	2102	45,216	45,216	6.780%	Yes	No	45,216	
740	**Subtotal**		-	-	**$102,646**	**$45,216**	-	**Yes**	**No**	**$45,216**	
741											
742	FY 2058	BOISE	2008	2058	69	-0	4.375%	No	No	-0	
743	FY 2058	BONNEVILLE	2008	2058	14,609	-0	4.375%	No	No	-0	
744	FY 2058	COLUMBIA BASIN	2008	2058	837	0	4.375%	No	No	0	

Table 13: Application of Amortization FY 2011
($000s)

	A	B	C	D	E	F	G	H	I	J	K
1	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized	
745	FY 2058	DWORSHAK	2008	2058	22	-0	4.375%	No	No	-0	
746	FY 2058	COLUMBIA RIVER FISH MITIGATION	2008	2058	37,277	-0	4.375%	No	No	-0	
747	FY 2058	HUNGRY HORSE	2008	2058	76	0	4.375%	No	No	0	
748	FY 2058	ICE HARBOR	2008	2058	14	-0	4.375%	No	No	-0	
749	FY 2058	LIBBY	2008	2058	1,652	-0	4.375%	No	No	-0	
750	FY 2058	LITTLE GOOSE	2008	2058	14	-0	4.375%	No	No	-0	
751	FY 2058	LOWER GRANITE	2008	2058	1	0	4.375%	No	No	0	
752	FY 2058	LOWER MONUMENTAL	2008	2058	42	-0	4.375%	No	No	-0	
753	FY 2058	MCNARY	2008	2058	331	-0	4.375%	No	No	-0	
754	FY 2058	MINIDOKA	2008	2058	0	-0	4.375%	No	No	-0	
755	FY 2058	ALBENI FALLS	2058	2103	45,864	45,864	6.780%	Yes	No	45,864	
756	**Subtotal**		-	-	**$100,810**	**$45,864**	-	**Yes**	**No**	**$45,864**	
757											
758	FY 2059	ALBENI FALLS	2059	2104	46,542	46,542	6.780%	Yes	No	46,542	
759	**Subtotal**		-	-	**$46,542**	**$46,542**	-	**Yes**	**No**	**$46,542**	
760											
761	FY 2060	ALBENI FALLS	2060	2105	47,245	47,245	6.780%	Yes	No	47,245	
762	**Subtotal**		-	-	**$47,245**	**$47,245**	-	**Yes**	**No**	**$47,245**	
763											
764	FY 2062	ALBENI FALLS	2017	2062	106,715	0	6.780%	Yes	No	0	
765	**Subtotal**		-	-	**$106,715**	**$0**	-	**Yes**	**No**	**$0**	
766											
767	**Grand Total**		-	-	**$12,070,903**	**$9,240,762**	-	**Yes**	**Yes**	**$8,463,077**	

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BONNEVILLE POWER ADMINISTRATION
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