

**2010 BPA Rate Case
Wholesale Power Rate Final Proposal**

**REVENUE REQUIREMENT
STUDY**

July 2009

WP-10-FS-BPA-02



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REVENUE REQUIREMENT STUDY

TABLE OF CONTENTS

	Page
Commonly Used Acronyms	iv
1. INTRODUCTION	1
2. SPENDING LEVEL DEVELOPMENT.....	4
2.1 Development Process for WP-10 Final Proposal Spending Levels.....	4
2.1.1 Regional Dialogue	4
2.1.2 Integrated Business Review	5
2.1.3 Integrated Program Review	5
2.2 Capital Funding.....	7
2.2.1 Bonds Issued to the U.S. Treasury.....	8
2.2.2 Federal Appropriations	8
2.2.3 Third-Party Debt.....	9
2.3 Debt Optimization Program.....	9
3. DEVELOPMENT OF REVENUE REQUIREMENTS	11
4. GENERATION REVENUE REQUIREMENT	13
4.1 Revenue Requirement Format	13
4.1.1 Income Statement.....	14
4.1.2 Statement of Cash Flows	21
4.2 Current Revenue Test	25
4.3 Revised Revenue Test.....	25
4.4 Repayment Test at Proposed Rates.....	26
5. REVENUE REQUIREMENT LEGAL REQUIREMENTS AND POLICIES	29
5.1 Development of BPA’s Revenue Requirements.....	29
5.1.1 Legal Requirements Governing the FCRPS Revenue Requirement.....	29
5.1.2 Colville Settlement Act Credits	32
5.1.3 The BPA Appropriations Refinancing Act.....	33
5.2 Allocation of Federal Columbia River Power System (FCRPS) Costs	34
5.2.1 Section 4(h)(10)(C) Credit.....	36
5.2.2 Equitable Allocation of Transmission Costs.....	37
5.3 Repayment Requirements and Policies.....	37

TABLES & FIGURE

Table 1: Projected Net Revenues from Projected Rates	44
Table 2: Planned Federal Amortization & Irrigation Assistance Payments	44
Table 3: Composition of Annual Amortization Payments.....	45
Table 4: FCRPS Projected Capital Funding Requirements	45
Table 5A: Generation Revenue Requirement Income Statement	46
Table 5B: Generation Revenue Requirement Statement of Cash Flows	47
Table 6A: Generation Current Revenue Test Income Statement.....	48
Table 6B: Generation Current Revenue Test Statement of Cash Flows.....	49
Table 7: Generation Revenues from Current Rates – Results Through the Repayment Period..	50
Table 8A: Generation Revised Revenue Test Income Statement	52
Table 8B: Generation Revised Revenue Test Statement of Cash Flows	53
Table 9: Generation Revenues from Proposed Rates – Results Through the Repayment Period	54
Table 10: Amortization of Generation Investments Over Repayment Period.....	55
Table 10: Amortization of Generation Investments Over Repayment Period.....	56
Figure 1: Revenue Requirement Process	57

APPENDICES

Appendix A: Integrated Program Review (IPR)

Appendix B: Repayment Program Tables

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 ratio 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 (pertains to generation movement)
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
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 (pertains to generation movement)
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)
kVAr	kilo-volt ampere reactive
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
MVA	mega-volt ampere
MVAr	mega-volt 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 (officially 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 respectively, contain key technical assumptions and calculations, the results of the generation
2 repayment studies, and a further explanation of the repayment program and its outputs.

3
4 The revenue requirement for this Study is developed using a cost accounting analysis comprised
5 of three parts. First, repayment studies for the generation function are prepared to determine the
6 schedule of amortization payments and to project annual interest expense for bonds and
7 appropriations that fund the Federal investment in hydro, fish and wildlife recovery,
8 conservation, and related generation assets. Repayment studies are conducted for each year of
9 the rate test period and extend over the 50-year repayment period. Second, generation operating
10 expenses and minimum required net revenues (MRNR) are projected for each year of the rate
11 test period. Third, annual Planned Net Revenues for Risk (PNRR) are determined after taking
12 into account risks, BPA's cost recovery goals, and other risk mitigation measures, as described in
13 the Risk Analysis and Mitigation Study, WP-10-FS-BPA-04. From these three steps, the
14 revenue requirement is set at the revenue level necessary to fulfill cost recovery requirements
15 and objectives through the process depicted in Figure 1, Generation Revenue Requirement
16 Process.

17
18 Consistent with Department of Energy (DOE) order RA 6120.2, described in Chapter 5 of this
19 Study, and the standards applied by the Commission on review of BPA's rates, the adequacy of
20 both current and proposed rates must be demonstrated. BPA conducts a current revenue test to
21 determine whether revenues projected from current rates meet cost recovery requirements for the
22 rate test period and the repayment period. If the current revenue test indicates that cost recovery
23 and risk mitigation requirements are met, current rates could be extended through the proposed
24 rate approval period. The current revenue test, described in section 4.2 of this Study,
25 demonstrates that revenues from current rates will not recover the generation revenue
26 requirement for the rate test period. The revised revenue test determines whether projected

1 revenues from proposed rates meet cost recovery requirements and objectives for the rate test
2 and repayment periods. The revised revenue test, contained in section 4.3 of this Study,
3 demonstrates that revenues from the proposed wholesale power rates will recover generation
4 costs in the rate test period as well as over the ensuing 50-year repayment period. Rate test
5 period costs are projected to be recovered with a very high confidence level, meeting BPA's
6 95 percent probability standard that all U.S. Treasury payments in the generation function will be
7 recovered on time and in full through wholesale power rates for a two-year period. *See Risk*
8 *Analysis and Mitigation Study, WP-10-FS-BPA-04.*

9
10 Table 1 summarizes the revised revenue test and shows projected net revenues from proposed
11 rates for FY 2010-2011. These net revenues are the lowest level necessary to achieve BPA's
12 cost recovery objectives, when combined with other risk mitigation tools, given hydro condition
13 uncertainty, market price volatility, and other risks.

14
15 Table 2 and Table 3 show planned generation amortization payments to the U.S. Treasury during
16 the rate test period and irrigation assistance payments that are due to be paid from power
17 revenues. To accommodate projected cash flows, it was necessary to shift \$42 million in
18 planned amortization from FY 2011 to FY 2010. This was accomplished without changing the
19 total amount planned for the rate period. This reshaping of amortization has been a longstanding
20 practice in BPA rate proposals. *See, for example, WP-07 Revenue Requirement Study,*
21 *WP-07-FS-BPA-02.*

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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.

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

4
5 Comments gathered in these forums included an early request by participants for additional
6 information about possible alternative program levels. On July 29, 2008, BPA released a “draft
7 report.” The draft report did not propose different spending levels for the FY 2010-2011 period,
8 although it did provide two illustrative scenarios for each program, one that explored the impacts
9 of a 10-percent increase and one that explored the impacts of a 10-percent decrease in proposed
10 program spending levels. This material was also presented and discussed at the July 30
11 workshop.

12
13 The public comment period ran from May 15, 2008, to August 15, 2008. Based on comments
14 received during the IPR process, BPA changed some forecast program spending levels for the
15 WP-10 Initial Proposal. These changes included an \$18 million reduction to Conservation
16 capital in FY 2010 and a \$10 million reduction to Conservation capital in FY 2011. The
17 renewable rate credit, originally proposed to be zero in the initial IPR, has been increased to
18 \$4 million in FY 2010 and \$2.5 million in FY 2011. Many of the forecasts in the initial IPR
19 were not modified. However, BPA committed to an additional, abbreviated IPR process outside
20 of this rate proceeding during the spring of 2009 to review spending forecasts for FY 2010-2011,
21 considering any new information available at that time, and to update forecasts if necessary. The
22 IPR FY 2010-2011 Power and Transmission Program Levels Final Report, included in Appendix
23 A of this Study, describes in greater detail the outcomes of the IPR process.

24
25 The abbreviated review process, known as IPR 2, began with a kickoff workshop on March 18,
26 2009. This effort consisted of three workshops that reviewed BPA’s program spending forecasts

1 as well as risk mitigation tools available to minimize a possible rate increase given the
2 deteriorating economic conditions in the region. For the rate period, BPA chose to modify some
3 of its forecasts such as CGS (\$50 million), Corps/Reclamation projects (\$12 million), Internal
4 Operations (\$17 million), Fish and Wildlife (\$15 million), and Long Term Generation Projects
5 (\$3.2 million). In total, program spending forecasts were reduced by an average of \$50 million
6 per year. The results of IPR 2 are reflected in this study.

8 **2.2 Capital Funding**

9 The forecast of FCRPS capital investments for FY 2010-2011 used in the WP-10 Final Proposal
10 was produced in the IPR. The following section reflects forecasts developed in the IPR with
11 inclusion of a 15 percent “lapse factor,” recognizing that timing of planned capital spending may
12 be stretched into the following rate period. The lapse factor was applied to all programs except
13 the Fish and Wildlife Program and CGS. FCRPS capital investments include COE, Reclamation,
14 and BPA capital investments as well as third-party resource investments for which debt is
15 secured by BPA (capitalized contracts). Projections of current FCRPS capital outlays are \$1,266
16 million for the cost evaluation period. These investments include:

- 17 • improvements and maintenance needed to increase reliability, safety, and
18 performance at the CGS nuclear plant;
- 19 • improvements and maintenance needed to improve reliability of the aging and
20 deteriorating Federal hydro system;
- 21 • investment in fish and wildlife mitigation measures;
- 22 • investment in conservation activities; and
- 23 • investment in capital equipment.

24
25 Table 4 provides a detailed breakout of investment projections for the cost evaluation period,
26 FY 2009 through 2011. The FY 2009 projections are updated with forecasts through the second

1 quarter of FY 2009. This Study projects that no capital investments will be funded from current
2 revenues.

3 4 **2.2.1 Bonds Issued to the U.S. Treasury**

5 Bonds issued to the U.S. Treasury are the source of capital that will be used to finance
6 FY 2010-2011 BPA capital program investments and COE and Reclamation investments that
7 BPA has agreed to direct-fund under section 2406 of P.L. No. 102-486, 16 U.S.C. § 839d-1.
8 These expenditures include a projection of \$556 million, split among BPA Fish and Wildlife
9 direct program investments (\$130.0 million), conservation investments (\$72.4 million), BPA
10 capital equipment (\$24.9 million), and generating resource investments of the COE and
11 Reclamation (\$328.7million) during FY 2010-2011.

12
13 Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates
14 comparable to interest rates on securities issued by other agencies of the U.S. Government.
15 Interest rates on bonds projected to be issued are included in Chapter 6 of Volume 1 of the
16 Documentation, WP-10-FS-BPA-02A.

17 18 **2.2.2 Federal Appropriations**

19 The Study, in general, reflects that all COE and Reclamation capital investments in the FCRPS
20 will be financed by Federal appropriations unless they are direct-funded by BPA. This Study
21 includes projected appropriated investments totaling \$201.5 million during the rate period for
22 COE fish and wildlife mitigation and recovery measures through the Columbia River Fish
23 Mitigation (CRFM) project. No other appropriations-financed investments are forecast for the
24 rate period. Capital investments funded by this source do not become BPA's obligation to repay
25 until placed in service.

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

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

11 **2.2.3 Third-Party Debt**

12 Third-party debt differs from U.S. Treasury debt in that entities other than BPA or U.S. Treasury
13 issue the debt. BPA's promise to make payments serves as security for bonds or other debt that
14 the third party issues, resulting in wider market access and potentially more favorable interest
15 rates for the seller. Examples of acquisitions financed in this way include the Energy Northwest,
16 Inc. (EN) WNP-1, WNP-3, and CGS nuclear power projects and the Lewis County Public Utility
17 District Hydroelectric project (Cowlitz Falls). This Study includes debt service on \$149 million
18 in total projected CGS capital investments by EN to be financed by issuing bonds in FY 2010
19 and 2011. Each new projected capital investment is assigned an interest rate from the tax exempt
20 municipal bond yield curve corresponding with the term of the bond, as shown in Chapter 6 of
21 Volume 1 of the Documentation, WP-10-FS-BPA-02A.

23 **2.3 Debt Optimization Program**

24 After base power rates were filed for the FY 2002-2006 rate period, BPA instituted a Debt
25 Optimization Program (DOP) with EN as a means of replenishing Treasury borrowing authority.
26 Debt Optimization (DO) involves extending EN debt that has come due and using the cash flows

1 that would have gone to pay the EN debt to repay an equivalent amount of Federal debt. The
2 program has resulted in a considerable amount of Federal debt, primarily bonds issued to
3 Treasury but also some congressional appropriations, being paid well in advance of the
4 amortization schedules established in the WP-02 rate filing. As the program continued during
5 the FY 2007-2009 rate period, this created additional advance amortization, compared to the
6 schedules that would have been established without DO, for the subsequent rate periods through
7 FY 2012. Effectively, the extension of EN debt into the FY 2013-2018 period has advanced the
8 repayment of Federal debt relative to the amount that otherwise would have been scheduled to be
9 paid in that period. BPA has committed to EN that it would follow this program, matching
10 dollar-for-dollar the repayment of Federal obligations in the same year in which EN debt has
11 been extended, absent dire financial circumstances that might cause some delay in the payment
12 of the advanced portion of the amortization.

13
14 Although DO actions may occur during the cost evaluation period, only EN debt refinancing
15 transactions completed through FY 2009 are incorporated in the development of these rates. No
16 forecasts of DO actions have been included in rates. However, in establishing amortization
17 schedules for FY 2010-2011, EN bonds that were refinanced in FY 2001-2002 more than 90
18 days in advance of their due dates, known as advanced refundings, are taken into account in
19 preparing repayment studies in order to fulfill the commitment for the dollar-for-dollar
20 repayment of Federal obligations. The total planned annual amortization is derived through a
21 two-phase repayment study procedure. A base level of amortization is established for each year
22 of the rate period as though EN advanced refundings had not occurred. The additional
23 amortization equivalent to the EN principal advance refinanced in each year is then added to the
24 base schedule. Table 3 shows the composition of the resulting planned annual amortization
25 payments.

1 **3. DEVELOPMENT OF REVENUE REQUIREMENTS**

2

3 Typically, repayment studies are performed as the first step in determining revenue requirements.

4 The studies establish a schedule of annual U.S. Treasury amortization for the rate test period and

5 the resulting interest payments. Each repayment study covers a rate test year and the ensuing

6 repayment period, which extends to the last year by which all outstanding and projected

7 obligations must be repaid. For power repayment studies, that is 50 years.

8

9 In conducting the repayment studies, BPA includes as fixed inputs the annual debt service

10 payments associated with its capitalized contract obligations and the fixed annual payments

11 associated with long-term energy resource acquisition contracts. All outstanding and projected

12 generation repayment obligations for appropriated investments (including irrigation assistance)

13 and bonds issued to the U.S. Treasury are included to be scheduled for repayment. Funding for

14 replacements projected during the repayment period are also included in the repayment study,

15 consistent with the requirements of RA 6120.2.

16

17 Appropriations are scheduled to be repaid within the expected useful life of the associated

18 facility or 50 years, whichever is less. COE and Reclamation project replacements funded by

19 appropriations and placed in service in 1994 or later have repayment periods that are set at the

20 weighted average service life of all replacements going into service at that project in that year.

21

22 Bonds issued by BPA to the U.S. Treasury may include 3-year to 45-year terms, taking into

23 account the estimated average service lives for investments and prudent financing and cash

24 management factors. Some bonds are issued with a provision that allows the bond to be called

25 after a certain time, typically five years. Bonds may also be issued with no early call provision.

26 Early retirement of eligible bonds requires that BPA pay a bond premium to the U.S. Treasury.

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

3
4 Bonds are issued to finance BPA conservation acquisition, the Fish and Wildlife Program, and
5 COE and Reclamation investments direct-funded by BPA, and are repaid within the terms and
6 conditions of each bond issued to the U.S. Treasury. Bonds to finance fish and wildlife capital
7 investments are issued with maturities not to exceed 15 years, the same period over which BPA
8 amortizes these capital investments. COE and Reclamation direct-funding bonds are issued with
9 maturities not to exceed 45 years. Conservation bonds are issued with maturities that are
10 consistent with the period over which BPA amortizes these capital investments. Currently, BPA
11 has three amortization schedules for conservation assets. Investments made prior to FY 2002,
12 referred to as the Conservation Legacy program, have a straight-line, 20-year amortization
13 period. Investments made from FY 2002 through FY 2006, known as Conservation
14 Augmentation investments, have a declining 10-year amortization period to be completed by
15 2011. Investments made beginning in FY 2007, known as Conservation Acquisition
16 investments, have a straight-line five-year amortization period. *See Administrator's Record of*
17 *Decision, WP-07-A-02, section 4.4.*

18
19 Based on these parameters, the repayment study establishes a schedule of planned amortization
20 payments and resulting interest expense by determining the lowest levelized debt service stream
21 necessary to repay all generation obligations within the required repayment period.

22
23 Further discussion of the repayment program and tables is included in Appendix B of this Study
24 and in Chapter 9 of Volume 2 of the Documentation, WP-10-FS-BPA-02B. Chapter 5 of this
25 Study provides explanation of repayment policies and requirements.

1 amounts shown on the Statement of Cash Flows (Line 2) are then incorporated in the Income
2 Statement (Line 27).

3 4 **4.1.1 Income Statement**

5 Below is a line-by-line description of the components in the Income Statement (Table 5A).

6 Volume 1 of the Documentation, WP-10-FS-BPA-02A, provides additional information on the
7 development and use of the data contained in the tables.

8
9 **Power System Generation Resources (Line 2).** This category encompasses the costs
10 associated with power generated by Federal hydroelectric facilities operated by the COE and
11 Reclamation and power obtained through contracts for non-Federal resources and through energy
12 conservation. This category includes lines 3 through 11, described below.

13
14 **Operating Generation Resources (Line 3).** This category includes the operations and
15 maintenance expenses associated with power-producing resources including the CGS,
16 Reclamation, and COE, and the annual expenses associated with long-term contract generating
17 projects.

18
19 **Operating Generation Settlement Payments (Line 4).** A settlement agreement
20 between the Confederated Tribes of the Colville Reservation and the United States was signed in
21 2004 concerning the construction of Grand Coulee Dam. The Settlement Act (Public Law
22 103-436) ratifying the settlement agreement authorizes BPA to make annual payments to the
23 Tribes for the use of tribal lands for power production at the Columbia Basin project.

24
25 **Non-Operating Generation (Line 5).** This category includes the decommissioning
26 costs of the Trojan nuclear plant and the unfinished WNP-1 and WNP-3 nuclear plants.

1
2 **Contracted Power Purchases (Line 6).** This category includes short-term (balancing)
3 power purchases and hedging/mitigation.
4

5 **Augmentation Power Purchases (Line 7).** This category includes augmentation power
6 purchases, the DSI monetized power sale, and the PNCA headwater benefit. Augmentation
7 power purchase costs reflect the energy that BPA purchases in order to satisfy its obligation to
8 meet the load requirements for public utilities. The PNCA headwater benefit refers to the costs
9 associated with benefits BPA receives from storage projects in Canada.
10

11 **Exchanges and Settlements (Line 8).** This category represents the net benefits for
12 qualifying public utilities and IOUs that are calculated as part of the Residential Exchange
13 Program, as well as the cost for operating the program.
14

15 **Renewable Generation (Line 9).** This category reflects the operating expenses of
16 several generating projects fueled by renewable energy resources, such as wind, geothermal,
17 methane gas, solar, and “fish-friendly small hydro projects.”
18

19 **Generation Conservation (Line 10).** This category includes the cost of conservation
20 programs including Marketing Development, which are reimbursable contracts with equal and
21 offsetting revenues; Market Transformation; Legacy Conservation programs; Technology
22 Leadership; and Low-Income Weatherization.
23

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

1
2 **Transmission Acquisition and Ancillary Services (Line 12).** This category includes
3 the annual expenses associated with Power Services' Transmission Acquisition program. It
4 represents costs associated with services necessary to deliver energy from resources to markets
5 or loads. This includes transmission, ancillary services, and real power losses, as purchased from
6 BPA's Transmission Services business unit (TS) or non-Federal entities; TS embedded costs for
7 the facilities that integrate power from COE and Reclamation projects onto the transmission
8 system; and metering and communication requirements.

9
10 **Power Non-Generation Operations (Line 13).** This category reflects Power Services'
11 internal costs associated with supporting the power function. It includes the costs of activities
12 such as generation oversight, weather and streamflow forecasting, system operations planning,
13 schedule planning, pre-scheduling, after-the-fact accounting of power transactions, power
14 billing, customer account executives and customer service support staff, development and
15 administration of power sales contracts, PS strategy development, PS financial reporting,
16 analysis and budgeting, risk management, and PS human resources management.

17
18 **F&W/Environmental Requirements (Line 14).** BPA funds projects designed to
19 protect, mitigate and enhance fish and wildlife affected by the FCRPS in a manner consistent
20 with the NPCC Columbia River Basin Fish and Wildlife Program, and to implement
21 commitments made pursuant to Biological Opinions (BiOps) issued by NOAA Fisheries and the
22 U.S. Fish and Wildlife Service regarding species listed under the Endangered Species Act. This
23 line item includes the expense portion of BPA's Fish and Wildlife direct program, including staff
24 costs and operating expenses of fish and wildlife activities. These activities include measures to
25 implement the fish and wildlife mitigation consistent with the NPCC Fish and Wildlife Program

1 as well BiOps issued by the NOAA Fisheries for listed salmon and steelhead and the U.S. Fish
2 and Wildlife Service for listed bull trout and sturgeon.

3
4 **General and Administrative/Shared Services (Line 15).** This category represents the
5 allocated portion of BPA's Corporate General and Administrative costs, which are allocated to
6 the business lines. Major functions besides the Executive Office are Corporate Communication,
7 Finance, Diversity, and Safety. This category also includes Shared Services and the Civil
8 Service Retirement System (CSRS) expense. Shared Services represents the costs for
9 information technology services; infrastructure and maintenance; building rent, maintenance and
10 security; mail services; personnel services; library and printing services; internal training;
11 purchasing; and furniture. CSRS reflects the costs for the unfunded liability of the Civil Service
12 Retirement and Disability Fund, the Employees Health Benefit Fund, and the Employees Life
13 Insurance Fund.

14
15 **Other Income, Expenses, and Adjustments (Line 16).** This category consists of the
16 annual cost of the Flexible PF Rate Program.

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

22
23 **Depreciation (Line 18).** Depreciation is the annual capital recovery expense associated
24 with FCRPS plant-in-service. Reclamation and COE (including Lower Snake River Fish and
25 Wildlife Compensation Plan (LSRCP)) plant, including assets for fish and wildlife recovery, is
26 depreciated by the straight-line method of calculation, using the composite service life of all

1 projects, 75 years. Capital equipment (office furniture and fixtures, data processing hardware
2 and software, and communications equipment) is also depreciated by the straight-line method
3 using the average service lives for the particular categories of capital investment. *Id.*, Chapters 3
4 and 4.

5
6 **Amortization (Line 19).** Amortization is the annual capital recovery expense associated
7 with non-revenue-producing assets. Conservation investments are amortized over three different
8 periods, as described in Chapter 3. Legacy conservation investments prior to the FY 2002-2006
9 rate period are amortized using a straight-line, 20-year life. Conservation Augmentation
10 investments in the FY 2002-2006 period are amortized using a declining life method, with all
11 amortization being complete in FY 2011. Conservation Acquisition investments beginning in
12 FY 2007 are amortized using a straight-line, five-year life. *Id.*

13
14 **Total Operating Expenses (Line 20).** Total Operating Expenses is the sum of the above
15 expenses (Lines 2 through 15).

16
17 **Interest on Appropriated Funds (Line 23).** Interest on Appropriated Funds includes
18 interest on COE and Reclamation appropriations, as calculated in the generation repayment
19 studies. *Id.*, Chapters 4 and 6.

20
21 **Capitalization Adjustment (Line 24).** Implementation of the Refinancing Act entailed
22 a change in capitalization on BPA's financial statements. Outstanding appropriations were
23 reduced as a result of the refinancing by \$2,142 million in the generation function. The
24 reduction is recognized annually over the remaining repayment period of the refinanced
25 appropriations. The annual recognition of this adjustment is based on the increase in annual
26 interest expense resulting from implementation of the Refinancing Act, as shown in repayment

1 studies for the year of the refinancing transaction (1997). The capitalization adjustment is
2 included on the income statement as a non-cash contra-expense.

3
4 **Interest on Bonds Issued to U.S. Treasury (Line 25).** Interest on long-term debt
5 includes interest on bonds that BPA issues to the U.S. Treasury to fund investments in capital
6 equipment, conservation, and fish and wildlife, and to fund Reclamation and COE investments
7 under the Energy Policy Act of 1992 (EPA-92) (P.L. No. 102-486, 1992 U.S. Code Cong. &
8 Admin. News, 106 Stat. 2776). The interest expense is calculated in the generation repayment
9 studies. Any payments of call premiums for bonds projected to be amortized are included in this
10 line. Documentation, WP-10-FS-BPA-02A, Chapters 4 and 6.

11
12 **Amortization of Capitalized Bond Premiums (Line 26).** When a bond issued to the
13 U.S. Treasury is refinanced, any call premium resulting from early retirement of the original
14 bond is capitalized and included in the principal of the new bond. The capitalized call premium
15 is then amortized over the term of the new bond. The annual amortization is a non-cash
16 component of interest expense.

17
18 **Allowance for Funds Used During Construction (AFUDC) (Line 27).** AFUDC is a
19 credit against interest costs on long-term debt (Line 20). This reduction to gross interest reflects
20 an estimate of interest on the funds used during the construction period of facilities that have yet
21 to be placed in service. AFUDC is capitalized along with other construction costs and is
22 recovered through rates over the expected service life of the related plant as part of the
23 depreciation expense after the facilities are placed in service. AFUDC, which is calculated
24 outside the generation repayment studies, is associated with the COE and Reclamation capital
25 investments direct-funded by BPA, and BPA capital equipment.

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

7
8 **Net Interest Expense (Line 29).** Net Interest Expense is computed as the sum of Interest
9 on Appropriated Funds (Line 23), Capitalization Adjustment (Line 24), Interest on Bonds Issued
10 to U.S. Treasury (Line 25), Amortization of Capitalized Bond Premiums (Line 26), AFUDC
11 (Line 27), and Interest Credit (Line 28).

12
13 **Total Expenses (Line 30).** Total Expenses are the sum of Total Operating Expenses
14 (Line 20) and Net Interest Expense (Line 29).

15
16 **Minimum Required Net Revenues (Line 31).** MRNR, an input from Line 2 of the
17 Statement of Cash Flows (Table 5B), may be necessary to cover cash requirements in excess of
18 accrued expenses. An explanation of the method used for determining MRNR is included in
19 section 4.1.2.

20
21 **Planned Net Revenues for Risk (PNRR) (Line 32).** PNRR are the amount of net
22 revenues to be included in rates for financial risk mitigation. PNRR, starting reserves, the
23 cash-flow when non-cash expenses exceed cash payments, the CRAC, and other risk mitigation
24 tools are available to mitigate risk in FY 2007-2009, as discussed in the Risk Analysis and
25 Mitigation Study, WP-10-FS-BPA-04.

26

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

3
4 **Total Revenue Requirement (Line 30).** Total Revenue Requirement is the sum of Total
5 Expenses (Line 31) and Total Planned Net Revenues (Line 32).

6
7 **4.1.2 Statement of Cash Flows**

8 Below is a line-by-line description of each of the components in the Statement of Cash Flows
9 (Table 5B). Volumes 1 and 2 of the Documentation, WP-10-FS-BPA-02A and WP-10-FS-BPA-
10 02B, provide additional information related to the use and development of the data contained in
11 the table.

12
13 **Minimum Required Net Revenues (Line 2).** Determination of this line is a result of
14 annual cash inflows and outflows shown on the Statement of Cash Flows. MRNR may be
15 necessary so that the cash provided from operating activities will be sufficient to cover the
16 planned amortization and irrigation assistance payments (the difference between Lines 8 and 21)
17 without causing the Annual Increase (Decrease) in Cash (Line 22) to be negative. The MRNR
18 amount determined in the Statement of Cash Flows is incorporated in the Income Statement
19 (Line 31).

20
21 **Depreciation and Amortization (Line 4).** Depreciation and Amortization are from the
22 Income Statement (Table 5A), lines 18 and 19 respectively. They are included in computing
23 Cash Provided By Operating Activities (Line 8) because they are non-cash expenses of the
24 FCRPS.

1 **Amortization of Capitalized Bond Premiums (Line 5).** Amortization of capitalized
2 bond premiums is from the Income Statement (Table 5A, line 26). It is included in computing
3 Cash Provided By Operating Activities (Line 8) because it is a non-cash expense of the FCRPS.
4

5 **Capitalization Adjustment (Line 6).** Capitalization Adjustment is from the Income
6 Statement (Table 5A, Line 24). It is a non-cash contra-expense.
7

8 **Accrual Revenues (Line 7).** Accrual revenues are primarily associated with settlement
9 agreements reached in prior periods. The annual accrual revenues, which are part of the total
10 revenues recovering the FCRPS revenue requirement, are included here as a non-cash adjustment
11 to cash from current operations.
12

13 **Cash Provided By Operating Activities (Line 8).** Cash Provided By Current
14 Operations, the sum of Lines 2, 4, 5, 6, and 7, is available for the year to satisfy cash
15 requirements.
16

17 **Investment in Federal Utility Plant (Including AFUDC) (Line 11).** Investment in
18 Utility Plant represents the annual increase in additions to appropriated plant-in-service and to
19 capital expenditures for COE, Reclamation, and BPA construction work-in-progress funded by
20 bonds. Documentation, WP-10-FS-BPA-02A, Chapter 4.
21

22 **Investment in Conservation (Line 12).** Investment in Conservation represents the
23 annual increase in capital expenditures associated with Conservation programs. *Id.*
24

25 **Investment in Fish and Wildlife (Line 13).** Investment in Fish and Wildlife represents
26 the annual increase in BPA's capital expenditures to fund projects for the protection, mitigation,

1 and enhancement of fish and wildlife affected by the FCRPS in a manner consistent with the
2 NPCC's Columbia River Basin Fish and Wildlife Program and the BiOp issued by NMFS and
3 USFWS.

4
5 **Cash Used for Investment Activities (Line 14).** Cash Used for Investment Activities is
6 the sum of Lines 11, 12, and 13.

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

12
13 **Repayment of Treasury Debt (Line 17).** This is BPA's planned repayment of
14 outstanding bonds issued by BPA to the U.S. Treasury as determined in the generation
15 repayment studies. *Id.*, Chapter 6.

16
17 **Increase in Federal Construction Appropriations (Line 18).** Increase in
18 Congressional Capital Appropriations represents congressional appropriations projected to be
19 received during the year for COE and Reclamation capital projects. *Id.*, Chapter 4.

20
21 **Repayment of Federal Construction Appropriations (Line 19).** Repayment of Capital
22 Appropriations represents projected amortization of outstanding COE and Reclamation
23 appropriations as determined in the generation repayment studies. *Id.*, Chapter 6.

24
25 **Payment of Irrigation Assistance (Line 20).** Payment of Irrigation Assistance
26 represents the payment of appropriated capital construction costs of Reclamation irrigation

1 facilities that have been determined to be beyond the ability of the irrigators to pay and allocated
2 to generation revenues for repayment. *Id.*, Chapter 9.

3
4 **Cash Provided by Borrowing and Appropriations (Line 21).** Cash Provided by
5 Borrowing and Appropriations is the sum of Lines 16 through 20. This is the net cash-flow
6 resulting from increases in cash from new long-term debt and capital appropriations and
7 decreases in cash from repayment of long-term debt and capital appropriations.

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

16
17 **Planned Net Revenues for Risk (PNRR) (Line 23).** PNRR reflects the amounts
18 included in revenue requirements to meet BPA's risk mitigation objectives from Table 5A,
19 Line 32.

20
21 **Total Annual Increase (Decrease) in Cash (Line 24).** Total Annual Increase
22 (Decrease) in Cash is the sum of Lines 22 and 23. It is the total annual cash that is projected to
23 be available to add to BPA's cash reserves.

1 **4.2 Current Revenue Test**

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

8
9 **4.3 Revised Revenue Test**

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

17
18 BPA revised its estimate of the cost of the Residential Exchange Program to an annual average
19 \$267 million, including program support costs, because it is an outcome of the rate development
20 process. Table 5A, which serves as the starting point for the rate development process, includes
21 only the program support cost of the program of approximately \$2 million per year. This change
22 to the total Residential Exchange Program cost is incorporated in the revised revenue test, as it is
23 the most current spending level forecast for that program.

24
25 As noted previously in Chapter 1, it is necessary to shift a total of \$42 million in planned
26 amortization from FY 2011 to FY 2010. This action is taken because expected revenues in

1 FY 2011 are significantly lower than the cash requirements in that year, the highest of the rate
2 period. Expenses in FY 2011 are particularly high because of a planned extended outage of the
3 CGS nuclear plant for refueling and the replacement of condenser tubes. Consequentially,
4 amortization is reshaped, without changing the total planned amortization for the rate period, to
5 accommodate the shape of the revenue forecast. The results of amortization shift repayment
6 study are documented in the Documentation. Documentation, Volume 2, WP-10-FS-BPA-02B,
7 Chapter 7.

8
9 For the rate test period, the demonstration of the adequacy of proposed rates is shown on
10 Tables 8A (Income Statement) and 8B (Cash-Flow Statement). Table 8B, Statements of Cash
11 Flows, tests the sufficiency of the resulting Net Revenues from Table 8A (Line 28) for making
12 the planned annual amortization and irrigation assistance payments and achieving the
13 Administrator's financial objectives. This is demonstrated by the Annual Increase (Decrease) in
14 Cash (Line 22). The annual cash-flow (Line 22) must be at least zero to demonstrate the
15 adequacy of the projected revenues to cover all cash requirements. The results of the revised
16 revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery
17 requirements and meet risk mitigation policy for the rate period, FY 2010-2011.

18 19 **4.4 Repayment Test at Proposed Rates**

20 Table 9 demonstrates whether projected revenues from proposed rates are adequate to meet the
21 cost recovery criteria of RA 6120.2 over the repayment period. The data are presented in a
22 format consistent with the revised revenue tests (Tables 8A and 8B) and separate accounting
23 analyses. The focal point of these tables is the Net Position (Column K), which is the amount of
24 funds provided by revenues that remain after meeting annual expenses requiring cash for the rate
25 period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in
26 each of the years of the rate approval period through the repayment period, the projected

1 revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the
2 allowable time. As shown in Column K, the resulting Net Position is greater than zero for each
3 year of the rate approval period and in each year of the repayment period.
4

5 The historical data on this table have been taken from BPA's separate accounting analysis. The
6 rate test period data have been developed specifically for this rate filing. The repayment period
7 data are presented consistent with the requirements of RA 6120.2. Typically, the revenue test
8 through the repayment period uses expenses from the last year of the rate period. In this case,
9 expenses for the CGS nuclear plant are normalized, because it is on a two-year refueling cycle,
10 which results in low costs in the first year and high costs in the second year. FY 2011 is a
11 refueling year for CGS, which increases O&M costs for the facility and power purchase costs to
12 make up for the loss of generation during the refueling. The CGS outage in FY 2011 will be
13 longer than normal refueling and maintenance outages, due to a planned condenser tube
14 replacement project. The projection of these outage costs in every year of the repayment period
15 would misrepresent the costs associated with the CGS refueling cycle. For the purposes of this
16 revenue test, these costs have been normalized by averaging FY 2010 and FY 2011 CGS costs to
17 produce an average annual cost for the operation of CGS for the rate period. Augmentation
18 purchases are also normalized in this fashion because of higher than usual costs in FY 2011 to
19 make up for lost CGS generation.
20

21 Table 10 summarizes the amortization of Federal investments over the entire repayment period.
22 It displays the total investment costs of the generating projects through the cost evaluation
23 period, forecast replacements required to maintain the system through the repayment period, the
24 cumulative dollar amount of the generation investment placed in service, scheduled amortization
25 payments for each year of the repayment period (due and discretionary), unamortized
26 investments including replacements through the repayment period, unamortized obligations as

1 determined by a term schedule (if all obligations were paid at maturity and never early), and the
2 predetermined amortization payments and the unamortized amount of irrigation assistance for
3 each year of the repayment period.
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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):

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

6
7 Development of the FCRPS revenue requirements is a critical component of meeting this
8 ratemaking directive. Section 9 of the Transmission System Act, 16 U.S.C. § 838g, also strongly
9 reflects this cost recovery principle, providing that rates be set:

10
11 [A]t levels to produce such additional revenues as may be required, in the aggregate
12 with all other revenues of the Administrator, to pay when due the principal of,
13 premiums, discounts, and expenses in connection with the issuance of and interest
14 on all bonds issued and outstanding pursuant to this Act, and amounts required to
15 establish and maintain reserve and other funds and accounts established in
16 connection therewith.

17
18 Similar guidelines are provided in Section 7 of the Northwest Power Act, 16 U.S.C. § 839e.
19 Section 7(a)(1), 16 U.S.C. § 839e(a)(1), provides:

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

1 Columbia River Transmission System Act (16 U.S.C. § 838), Section 5 of
2 the Flood Control Act of 1944, and the provisions of this of this [Act].
3

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

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

15 16 U.S.C. § 839e(n).
16

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

20 Rates established under this section shall become effective only, except in
21 the case of interim rules as provided in subsection (i)(6) of this section,
22 upon confirmation and approval by the Federal Energy Regulatory
23 Commission upon a finding by the Commission, that such rates:

- 24 (A) are sufficient to assure repayment of the Federal investment in the
25 Federal Columbia River Power System over a reasonable number of
26 years after first meeting the Administrator's other costs,
27 (B) are based upon the Administrator's total system costs, and

1 (C) insofar as transmission rates are concerned, equitably allocate the
2 costs of the Federal transmission system between Federal and non
3 Federal power utilizing such system.
4

5 In addition to reiterating and clarifying the cost recovery principle, the Northwest Power Act
6 provided BPA with supplementary authority to sell bonds to the U.S. Treasury to finance BPA's
7 new conservation and renewable resource programs. *See* 16 U.S.C. § 838i. EPA-92 clarified
8 BPA's authority to provide funds directly to COE and Reclamation for hydroelectric generation
9 additions, improvements, and replacements, as well as O&M expenses. *See* P.L. No. 102-486,
10 1992 U.S. Code Cong. & Admin. News, 106 Stat. 2776. Other provisions that have particular
11 relevance to the repayment of power costs can be found in the Reclamation Project Act of 1939
12 (codified as amended in scattered sections of 43 U.S.C.); the Grand Coulee Dam - Third
13 Powerplant Act of June 14, 1966, P.L. No. 89-448, 80 Stat. 200, authorizing construction of the
14 Grand Coulee Dam Third Powerhouse; and P.L. No. 89-561, 80 Stat. 707, Act of September 7,
15 1966, which partially amended P. L. No. 89-448. The costs associated with these projects and
16 programs, as well as the other costs incurred by the Administrator in furtherance of BPA's
17 mission, are included in this Study.
18

19 **5.1.2 Colville Settlement Act Credits**

20 The Confederated Tribes of the Colville Reservation Grand Coulee Dam Settlement Act
21 approves and ratifies the Settlement Agreement entered into by the United States and the
22 Confederated Tribes of the Colville Reservation (Colville Tribes) related to the claims for a
23 portion of the revenues from Grand Coulee Dam, and directs BPA to carry out its obligations
24 under the settlement agreement. *See* P. L. No. 103-436, Nov. 2, 1994, 108 Stat. 4577.
25
26

1 The Settlement Agreement obligates BPA to make annual payments to the Colville Tribes.
2 Payments have been tied to both BPA's average prices and the amount of annual generation from
3 Grand Coulee Dam. Under the Refinancing Act, part of the Omnibus Consolidated Rescissions
4 and Appropriations Act of 1996, P.L. No. 104-13, 110 Stat. 1321, BPA receives annual credits
5 from the U.S. Treasury against payments due the U.S. Treasury in order to defray a portion of
6 the costs of making payments to the Colville Tribes. Revenues credited to BPA associated with
7 the Settlement Agreement are \$21.3 million in FY 2010 and \$21.7 million in FY 2011. The
8 credits for the FY 2010-2011 rate period are forecast to be \$4.6 million in each fiscal year.
9

10 **5.1.3 The BPA Appropriations Refinancing Act**

11 As in the prior rate periods, BPA's power rates for the FY 2010-2011 rate period will reflect the
12 requirements of the Refinancing Act, part of the Omnibus Consolidated Rescissions and
13 Appropriations Act of 1996, 16 U.S.C. § 838l, P.L. No. 104-134, 110 Stat. 1321, enacted in
14 April 1996. The Refinancing Act required that unpaid principal on FCRPS appropriations (old
15 capital investments) at the end of FY 1996 be reset at the present value of the principal and
16 annual interest payments BPA would make to the U.S. Treasury for these obligations absent the
17 Refinancing Act, plus \$100 million. *Id.* at § 838l(b)(I). The Refinancing Act also specifies that
18 the new principal amounts of the old capital investments be assigned new interest rates from the
19 U.S. Treasury yield curve prevailing at the time of the refinancing transaction. *Id.* at
20 § 838l(a)(6)(A).
21

22 The Refinancing Act specifies that repayment periods on new principal amounts may not be
23 earlier than determined prior to the refinancing. *Id.* at § 838l(d).
24

25 The Refinancing Act specifies that the prevailing U.S. Treasury yield curve will be used to
26 calculate interest during construction (IDC) and to assign interest rates to new capital

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

8
9 The U.S. Treasury rate for new capital investments prescribed in the Refinancing Act is:

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

16 16 U.S.C. § 838l(a)(6)(B).

17
18 The Refinancing Act also directed the Administrator to offer to provide assurance in new or
19 existing power, transmission, or related service contracts that the government would not increase
20 the repayment obligations in the future. *See* 16 U.S.C. § 838l(i). The Refinancing Act also
21 amends the Colville Settlement Act to modify the amount and timing of certain credits that BPA
22 takes against its annual cash transfers to U.S. Treasury.

23 24 **5.2 Allocation of Federal Columbia River Power System (FCRPS) Costs**

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

1
2 For projects that provide power resources to the FCRPS, this allocation has generally been
3 accomplished pursuant to statutory direction. For example, Section 7 of the Bonneville Project
4 Act, 16 U.S.C. § 832f, requires that BPA's rates be based, *inter alia*, on "an allocation of costs
5 made by the [Secretary of Energy,]" and, insofar as costs of the Bonneville Project were
6 concerned:

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

11 *Id.*

12
13 Similar allocations for projects constructed pursuant to various Reclamation laws have been
14 performed by the Secretary of the Interior under the authority of 43 U.S.C. § 485h(a)-(b). Cost
15 allocations for projects constructed by the COE have also been performed by the Secretary of the
16 Army and approved by the Federal Power Commission (the predecessor to the Federal Energy
17 Regulatory Commission).

18
19 On a generic level, an attempt is made to allocate the specific cost of each feature of a
20 multi-purpose dam to the purpose it serves. For example, the costs of powerhouses, penstocks,
21 and other specific power-related facilities have been allocated to power, whereas the costs of
22 navigation locks have been allocated to navigation. More problematic are the joint-use costs that
23 remain unallocated after the specific costs identifiable to a single purpose have been allocated.
24 The joint-use formulas attempt to account for the relative benefits provided by each function, and
25 costs are allocated accordingly.

1 Thus, costs assigned to the power production functions include specific cost items whose sole
2 purpose is power production and the “power production share” of joint costs assigned to more
3 than one purpose. Both types of costs are included in BPA’s power revenue requirement.
4

5 **5.2.1 Section 4(h)(10)(C) Credit**

6 The Northwest Power Act provides that:

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

13 16 U.S.C. § 839b(h)(10)(A).
14

15 BPA is not obligated to reimburse the U.S. Treasury for the non-power portion of these fish and
16 wildlife costs. Such non-power costs are instead allocated to the various project purposes by the
17 BPA Administrator, in consultation with the COE and Reclamation, pursuant to
18 section 4(h)(10)(C) of the Northwest Power Act. 16 U.S.C. § 839b(h)(10)(C). This allocation to
19 various project purposes is intended to implement the principle that electric power consumers
20 bear no greater share of the costs of fish and wildlife mitigation than the power portion of the
21 project.
22

23 The legislative history of section 4(h)(10)(C) illustrates how the expenditures by the
24 Administrator for protection, mitigation, and enhancement of fish and wildlife at individual
25 Federal projects in excess of the portion allocable to electric consumers is to be treated as a
26 credit for electric consumers. *See* H.R. Rep. No. 976, 96th Cong., 2d Sess., pt. 2 at 45 (1980),
27 *reprinted in* 1980 U.S.C.C.A.N. 5989, 6011. This principle is satisfied by treating expenditures

1 on behalf of non-power purposes as other project costs. These amounts are regarded as having
2 been applied toward other project costs properly allocable to the power function and payable to
3 the U.S. Treasury. Thus, BPA receives a credit against its cash transfers to the U.S. Treasury for
4 expenditures attributable to other project purposes. The cost-sharing arrangements with the
5 Administration implement the section 4(h)(10)(C) directives. BPA's initial funding of all the
6 costs for fish and wildlife has the advantage of avoiding the need for funding the non-power
7 portion of these costs through the annual appropriations process.

9 **5.2.2 Equitable Allocation of Transmission Costs**

10 In an order dated January 27, 1984, *United States Department of Energy – Bonneville Power*
11 *Admin.*, 26 FERC ¶ 61,096 (1984), the Commission directed BPA to, among other things,
12 develop separate repayment studies for the generation and transmission functions of the FCRPS.
13 The purpose of this requirement was to assist the Commission in making the determination
14 required under section 7(a)(2)(C) of the Northwest Power Act (16 U.S.C. § 839e(a)(2)(C)) that
15 transmission costs be equitably allocated between Federal and non-Federal use of the
16 transmission system. This requirement has given BPA a 25-year history of conducting separate
17 repayment studies for the transmission and generation functions, which has enabled BPA to
18 transition to a bifurcated ratesetting process with minimal change in repayment policy and
19 development of the revenue requirement. Consistent with the decision to separate the rates for
20 the transmission and generation functions beginning with the WP-02 proceeding, this Revenue
21 Requirement Study incorporates only the separate repayment study for the generation function of
22 the FCRPS for FY 2010-2011. *See also* Transmission Revenue Requirement Study, TR-10-FS-
23 BPA-01.

25 **5.3 Repayment Requirements and Policies**

26 The statutes do not include specific directives for scheduling repayment of the FCRPS capital

1 appropriations and bonds issued to the U.S. Treasury. The details of the repayment policy have
2 largely been established through administrative interpretation of statutory requirements, with
3 congressional sanction.

4
5 There have been a number of changes in BPA's repayment policy over the years concurrent with
6 expansion of the FCRPS and changing conditions. In general, current repayment criteria were
7 first approved by the Secretary of the Interior on April 3, 1963. These criteria were refined and
8 submitted to the Secretary and the Federal Power Commission in support of BPA's rate filing in
9 September 1965.

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

15 Accordingly, in a repayment study there is no annual schedule of capital
16 repayment. The test of the sufficiency of revenues is whether the capital
17 investment can be repaid within the overall repayment period established
18 for each power project, each increment of investment in the transmission
19 system, and each block of irrigation assistance. Hence, repayment may
20 proceed at a faster or slower pace from year-to-year as conditions change.

21 This approach to repayment scheduling has the effect of averaging the
22 year-to-year variations in costs and revenues over the repayment period.
23 This results in a uniform cost per unit of power sold, and permits the
24 maintenance of stable rates for extended periods. It also facilitates the
25 orderly marketing of power and permits Bonneville Power Administration's
26 customers, which include both electric utilities and electro-process
27 industries, to plan for the future with assurance.

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

5 A. Hydroelectric power, although not a primary objective, will be
6 proposed to Congress and supported for inclusion in
7 multiple-purpose Federal projects when ... it is capable of repaying
8 its share of the Federal investment, including operation and
9 maintenance costs and interest, in accordance with the law.

10 B. Electric power generated at Federal projects will be marketed at the
11 lowest rates consistent with sound financial management. Rates for
12 the sale of Federal electric power will be reviewed periodically to
13 assure their sufficiency to repay operating and maintenance costs
14 and the capital investment within 50 years with interest that more
15 accurately reflects the cost of money.

16
17 To achieve a greater degree of uniformity in a repayment policy for all DOI power marketing
18 agencies, of which BPA was one at the time, the Deputy Assistant Secretary issued a memo on
19 August 2, 1972, outlining: (1) a uniform definition of the commencement of the repayment
20 period for a particular project; (2) the method for including future replacement costs in
21 repayment studies; and (3) a provision that the investment or obligation bearing the highest
22 interest rate shall be amortized first, to the extent possible, while still complying with the
23 repayment period established for each increment of investment.

24
25 A further clarification of the repayment policy was outlined in a joint memo of January 7, 1974,
26 from the Assistant Secretary for Reclamation and Assistant Secretary for Energy and Minerals.
27 This memo states that, in addition to meeting the overall objective of repaying the Federal
28 investment or obligations within the prescribed repayment periods, revenues shall be adequate,

1 except in unusual circumstances, to repay annually all costs for O&M, purchased power, and
2 interest.

3
4 On March 22, 1976, the DOI issued Chapter 4 of Part 730 of the DOI Manual to codify financial
5 reporting requirements for the DOI power marketing agencies. Included therein are standard
6 policies and procedures for preparing system repayment studies.

7
8 BPA and other former DOI power marketing agencies were transferred to the newly established
9 DOE on October 1, 1977. *See* DOE Organization Act, 42 U.S.C. § 7101 *et seq.* (1994). The
10 DOE adopted the policies set forth in Part 730 of the DOI Manual by issuing Interim
11 Management Directive No. 1701 on September 28, 1977, which was subsequently replaced by
12 RA 6120.2 on September 20, 1979, as amended on October 1, 1983.

13
14 The repayment policy outlined in RA 6120.2, paragraph 12, provides that BPA's total revenues
15 from all sources must be sufficient to:

- 16
17 (1) Pay all annual costs of operating and maintaining the Federal power system;
18
19 (2) Pay the cost each FY of obtaining power through purchase and exchange agreements,
20 the cost for transmission services, and other costs during the year in which such costs
21 are incurred;
22
23 (3) Pay interest each year on the unamortized portion of the commercial power
24 investment financed with appropriated funds at the interest rates established for each
25 generating project and for each annual increment of such investment in the BPA
26 transmission system, except that recovery of annual interest expense may be deferred
27 in unusual circumstances for short periods of time;
28

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

3
4 (5) Repay:

- 5 • each dollar of power investments and obligations in the FCRPS generating
6 projects within 50 years after the projects become revenue-producing (50 years
7 has been deemed a “reasonable period” as intended by Congress, except for the
8 Yakima-Chandler Project, which has a legislated amortization period of 66 years);
- 9 • each annual increment of transmission financed by Federal investments and
10 obligations within the average service life of such transmission facilities
11 (currently 40 years) or within a maximum of 50 years, whichever is less [BPA has
12 interpreted RA 6120.2 to require repayment of bonds sold to finance conservation
13 to be within the average service lives of these projects, currently estimated to be
14 five years, and for fish and wildlife facilities to be 15 years];
- 15 • the Federally -financed amount of each replacement within its service life up to a
16 maximum of 50 years; and

17
18 (6) As required by P.L. No. 89-448, repay the portion of construction costs at Federal
19 reclamation projects that is beyond the repayment ability of the irrigators, and which
20 is assigned for repayment from commercial power revenues, within the same overall
21 period available to the irrigation water users for making their payments on
22 construction costs.

23
24 The typical repayment period for appropriated capital investments is 50 years from the year in
25 which the plant is placed in service. The Refinancing Act overrides provisions in RA 6120.2
26 related to determining interest during construction and assigning interest rates to Federal
27 investments financed by appropriations. The Refinancing Act also contains provisions on
28 repayment periods (due dates) for these investments. The Refinancing Act is discussed in
29 section 5.1.3.

30
31 Irrigation costs are repaid without interest. P.L. No. 89-448 authorizes the payment of irrigation

1 costs from revenues of the entire power system. This is consistent with the so-called “Basin
2 Account” concept. P.L. No. 89-561, approved on September 7, 1966, amended P.L. No. 89-448
3 to provide several limitations on the repayment of irrigation costs from power revenues. These
4 limitations are:

5
6 (1) the irrigation costs are to be paid from “net revenues” of the power system, with net
7 revenues defined as those revenues over and above the amount needed to cover power
8 costs and previously authorized irrigation payments;

9
10 (2) the construction of new Federal irrigation projects will be scheduled, *i.e.*, deferred, if
11 necessary, so that the repayment of the irrigation costs from power revenues will not
12 require an increase in the BPA power rate level; and

13
14 (3) the total amount of irrigation costs to be repaid from power revenues shall not
15 average more than \$30 million per year in any period of 20 consecutive years.

16
17 In addition, other sections within RA 6120.2 require that any outstanding deferred interest
18 payments must be repaid before any planned amortization payments are made. Also, repayments
19 are to be made by amortizing those Federal investments and obligations bearing the highest
20 interest rate first, to the extent possible, while still completing repayment of each increment of
21 Federal investment and obligation within its prescribed repayment period.

TABLES & FIGURE

Table 1: Projected Net Revenues from Projected Rates
(\$000s)

	A	B	C
1		FY 2010	FY 2011
2	Projected Revenues from Proposed Rates	\$ 2,877,961	\$ 2,972,201
3	Projected Expenses	<u>2,764,182</u>	<u>2,966,653</u>
4	Net Revenues	\$ 113,779	\$ 5,548

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

	A	B	C	D
			Scheduled But	
1	Bonds	Due	Not Due	Total
2	2010	68	0	68
3	2011	<u>60,000</u>	<u>0</u>	<u>60,000</u>
4	Subtotal	60,068	0	60,068
5	Appropriations			
6	2010	0	244,605	244,605
7	2011	<u>0</u>	<u>102,163</u>	<u>102,163</u>
8	Subtotal	0	346,768	346,768
9	Irrigation Assistance			
10	2010	0	0	0
11	2011	<u>0</u>	<u>0</u>	<u>0</u>
12	Subtotal	0	0	0
13	TOTAL			
14	2010	68	244,605	244,673
15	2011	<u>60,000</u>	<u>102,163</u>	<u>162,163</u>
16	Subtotal	60,068	346,768	406,836

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

	A	B	C	D
1		Base	Advanced	Total
2	Fiscal Year	Amortization	Amortization	Amortization
3	2010	\$206,173	\$38,500	\$244,673
4	2011	<u>\$92,163</u>	<u>\$70,000</u>	<u>\$162,163</u>
5	Total	\$298,336	\$108,500	\$406,836

Table 4: FCRPS Projected Capital Funding Requirements
(\$000s)

	A	B	C	D	E
1			FY 2009	FY 2010	FY 2011
2	POWER				
3	Capital Requirements for Revenue Producing Investments				
4	Corps & Bureau Additions/Replacements - Direct Funded		105,000	157,581	171,208
5	PBL Capital Equipment		10,000	12,027	12,882
6	CGS: Additions/Replacements		26,000	92,000	54,000
8	Annual Capital Requirements for Revenue Producing Investments		141,000	261,608	238,090
10					
11	Capital Requirements for Non-Revenue Producing and Public Benefit Investments				
12	Energy Conservation		15,000	32,819	39,592
13	Fish Investment				
14	BPA Fish and Wildlife Investment		40,000	70,000	60,000
15	Corps & Bureau Fish Investment - Appropriations		166,473	101,454	100,066
16	Total Fish Investment		206,473	171,454	160,066
17	Other Third - Party		-	-	-
19	Annual Capital Req. for Non-Rev. & Public Benefit Invests.		221,473	204,273	199,658
22	ANNUAL FUNDING REQUIREMENTS FOR POWER		362,473	465,881	437,748
24	CUMULATIVE FUNDING REQUIREMENTS FOR POWER		362,473	828,354	1,266,102

Table 5A: Generation Revenue Requirement Income Statement

(\$000s)

	A	B
	2010	2011
1 OPERATING EXPENSES		
2 POWER SYSTEM GENERATION RESOURCES		
3 OPERATING GENERATION	566,645	644,193
4 OPERATING GENERATION SETTLEMENT PAYMENT	21,328	21,754
5 NON-OPERATING GENERATION	2,618	2,728
6 CONTRACTED POWER PURCHASES	89,673	74,727
7 AUGMENTATION POWER PURCHASES	180,599	272,917
8 EXCHANGES & SETTLEMENTS	2,421	1,440
9 RENEWABLE GENERATION	45,588	44,638
10 GENERATION CONSERVATION	55,988	55,622
11 CONSERVATION AND RENEWABLE DISCOUNT	28,000	29,500
12 PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	177,717	176,591
13 POWER NON-GENERATION OPERATIONS	78,601	81,667
14 F&W/USF&W/PLANNING COUNCIL/ENVIRONMENTAL REQUIREMENTS	248,583	270,714
15 GENERAL AND ADMINISTRATIVE/SHARED SERVICES	65,408	65,643
16 OTHER INCOME, EXPENSES AND ADJUSTMENTS	0	0
17 NON-FEDERAL DEBT SERVICE	565,486	581,494
18 DEPRECIATION	120,111	121,235
19 AMORTIZATION	77,728	85,699
20 TOTAL OPERATING EXPENSES	2,326,493	2,530,562
21 INTEREST EXPENSE:		
22 INTEREST		
23 APPROPRIATED FUNDS	223,278	212,832
24 CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
25 BONDS ISSUED TO U.S. TREASURY	42,061	58,140
26 AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
27 ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(11,437)	(10,896)
28 INTEREST CREDIT	(41,032)	(41,023)
29 NET INTEREST EXPENSE	167,119	173,301
30 TOTAL EXPENSES	2,493,611	2,703,863
31 MINIMUM REQUIRED NET REVENUES 1/	54,110	46,505
32 PLANNED NET REVENUES FOR RISK		
33 PLANNED NET REVENUES, TOTAL (31+32)	54,110	46,505
34 TOTAL REVENUE REQUIREMENT	2,547,722	2,750,369

1/ SEE NOTE ON CASH FLOW STATEMENT

Table 5B: Generation Revenue Requirement Statement of Cash Flows

(\$000s)

	A	B
	2010	2011
1 CASH PROVIDED BY OPERATING ACTIVITIES		
2 MINIMUM REQUIRED NET REVENUES 1/	54,110	46,505
3 NON-CASH ITEMS:		
4 DEPRECIATION AND AMORTIZATION	197,839	206,934
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	202,673	204,163
9 CASH USED FOR INVESTMENT ACTIVITIES:		
10 INVESTMENT IN:		
11 FEDERAL UTILITY PLANT (INCLUDING AFUDC)	(259,035)	(271,274)
12 CONSERVATION	(32,819)	(39,592)
13 FISH & WILDLIFE	(70,000)	(60,000)
14 CASH USED FOR INVESTMENT ACTIVITIES	(361,854)	(370,866)
15 CASH FROM AND (USED FOR) FINANCING ACTIVITIES		
16 INCREASE IN TREASURY DEBT	260,400	270,800
17 REPAYMENT OF TREASURY DEBT	(68)	(60,000)
18 INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	101,454	100,066
19 REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(202,605)	(144,163)
20 PAYMENT OF IRRIGATION ASSISTANCE	0	0
21 CASH USED FOR FINANCING ACTIVITIES	159,181	166,703
22 ANNUAL INCREASE (DECREASE) IN CASH	0	0
23 PLANNED NET REVENUES FOR RISK	0	0
24 TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0

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	B
	2010	2011
1 REVENUES FROM CURRENT RATES	2,777,787	2,874,922
2 OPERATING EXPENSES		
3 POWER SYSTEM GENERATION RESOURCES		
4 OPERATING GENERATION	566,645	644,193
5 OPERATING GENERATION SETTLEMENT PAYMENT	21,328	21,754
6 NON-OPERATING GENERATION	2,618	2,728
7 CONTRACTED POWER PURCHASES	89,673	74,727
8 AUGMENTATION POWER PURCHASES	180,766	273,043
9 EXCHANGES & SETTLEMENTS	265,558	270,087
10 RENEWABLE GENERATION	45,588	44,638
11 GENERATION CONSERVATION	55,988	55,622
12 CONSERVATION AND RENEWABLE DISCOUNT	28,000	29,500
13 PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	177,717	176,591
14 POWER NON-GENERATION OPERATIONS	78,601	81,667
15 F&W/USF&W/PLANNING COUNCIL/ENVIRONMENTAL REQUIREMENTS	248,583	270,714
16 GENERAL AND ADMINISTRATIVE/SHARED SERVICES	65,408	65,643
17 OTHER INCOME, EXPENSES AND ADJUSTMENTS	0	0
18 NON-FEDERAL DEBT SERVICE	565,486	581,494
19 DEPRECIATION	120,111	121,235
20 AMORTIZATION	77,728	85,699
21 TOTAL OPERATING EXPENSES	2,589,797	2,799,335
22 INTEREST EXPENSE:		
23 INTEREST		
24 APPROPRIATED FUNDS	223,278	214,120
25 CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
26 BONDS ISSUED TO U.S. TREASURY	42,061	58,140
27 AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
28 ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(10,800)	(10,200)
29 INTEREST CREDIT	(40,236)	(35,995)
30 NET INTEREST EXPENSE	168,552	180,313
31 TOTAL EXPENSES	2,758,348	2,979,648
32 NET REVENUES	19,439	(104,726)

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

(\$000s)

	A	B
	2010	2011
1 CASH PROVIDED BY OPERATING ACTIVITIES		
2 NET REVENUES	19,439	(104,726)
3 NON-CASH ITEMS:		
4 DEPRECIATION AND AMORTIZATION	197,839	206,934
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	168,001	52,931
9 CASH USED FOR INVESTMENT ACTIVITIES:		
10 INVESTMENT IN:		
11 FEDERAL UTILITY PLANT (INCLUDING AFUDC)	(259,035)	(271,274)
12 CONSERVATION	(32,819)	(39,592)
13 FISH & WILDLIFE	(70,000)	(60,000)
14 CASH USED FOR INVESTMENT ACTIVITIES	(361,854)	(370,866)
15 CASH FROM AND (USED FOR) FINANCING ACTIVITIES		
16 INCREASE IN TREASURY DEBT	361,854	370,866
17 REPAYMENT OF TREASURY DEBT	(68)	(60,000)
18 INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	0	0
19 REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(202,605)	(144,163)
20 PAYMENT OF IRRIGATION ASSISTANCE	0	0
21 CASH USED FOR FINANCING ACTIVITIES	159,181	166,703
22 ANNUAL INCREASE (DECREASE) IN CASH	(34,672)	(151,232)

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

(\$000s)

	A	B	C	D	E	F	G	H	I	J	K
			PURCHASE AND EXCHANGE POWER	DEPRECIATION	NET INTEREST	NET REVENUES	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)
YEAR COMBINED CUMULATIVE	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	(STATEMENT E)		(STATEMENT D)	(F=A-B-C-D-E)					
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	135,010	5/	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	773,510	1,436,548	181,878	157,609	304,114	(84,357)	537,237	261,276		275,961
2007	2,657,891	818,494	1,361,837	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	28,438	195,087	277,483	2,950	(85,346)
COST EVALUATION PERIOD											
2009	2,275,866	857,483	1,250,309	181,044	145,785	(158,755)	111,542	8,036	273,159	7,274	(272,397)
RATE APPROVAL PERIOD											
2010	2,777,787	958,002	1,433,955	197,839	168,552	19,439	152,087	168,001	202,673		(34,672)
2011	2,874,922	992,535	1,599,866	206,934	180,313	(104,726)	161,182	52,931	204,163		(151,232)
REPAYMENT PERIOD											
2012	2,874,922	992,535	1,611,165	206,934	188,641	(124,353)	161,182	33,305	97,948	1,206	(65,849)
2013	2,874,922	992,535	1,564,965	206,934	194,604	(84,115)	161,182	73,543	38,900	100,492	(65,849)
2014	2,874,922	992,535	1,596,807	206,934	200,478	(121,832)	161,182	35,826	15,950	85,726	(65,849)
2015	2,874,922	992,535	1,567,353	206,934	206,776	(98,677)	161,182	58,981	32,819	92,012	(65,849)
2016	2,874,922	992,535	1,644,401	206,934	214,964	(183,913)	161,182	(26,255)	39,592	0	(65,847)

Table 7 cont.

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)
2017	2,874,922	992,535	1,674,971	206,934	221,335	(220,852)	161,182	(63,194)	0	2,650	(65,844)
2018	2,874,922	992,535	1,500,095	206,934	224,913	(49,556)	161,182	108,102	145,963	27,989	(65,849)
2019	2,874,922	992,535	1,020,523	206,934	210,921	444,009	161,182	601,667	609,349	58,168	(65,849)
2020	2,874,922	992,535	1,118,655	206,934	178,443	378,355	161,182	536,013	576,920	24,943	(65,849)
2021	2,874,922	992,535	1,118,666	206,934	145,817	410,970	161,182	568,628	622,123	12,354	(65,849)
2022	2,874,922	992,535	1,118,661	206,934	109,988	446,804	161,182	604,462	655,726	14,585	(65,849)
2023	2,874,922	992,535	1,119,072	206,934	109,988	483,440	161,182	641,098	693,695	13,252	(65,849)
2024	2,874,922	992,535	1,161,666	206,934	49,670	464,117	161,182	621,775	672,210	15,414	(65,849)
2025	2,874,922	992,535	1,275,515	206,934	(2,570)	402,508	161,182	560,166	612,115	13,900	(65,849)
2026	2,874,922	992,535	1,275,292	206,934	(31,448)	431,609	161,182	589,267	633,963	21,154	(65,849)
2027	2,874,922	992,535	1,275,449	206,934	(58,129)	458,132	161,182	615,790	436,911	192,572	(13,693)
2028	2,874,922	992,535	1,275,617	206,934	(74,373)	474,209	161,182	631,867	57,284	0	574,583
2029	2,874,922	992,535	1,275,797	206,934	(74,369)	474,025	161,182	631,683	51,431	0	580,252
2030	2,874,922	992,535	1,275,990	206,934	(74,364)	473,828	161,182	631,486	46,309	0	585,177
2031	2,874,922	992,535	1,276,194	206,934	(74,359)	473,618	161,182	631,276	71,752	0	559,524
2032	2,874,922	992,535	1,276,414	206,934	(75,851)	474,890	161,182	632,548	37,729	0	594,819
2033	2,874,922	992,535	1,276,648	206,934	(75,845)	474,650	161,182	632,308	73,903	0	558,405
2034	2,874,922	992,535	1,276,898	206,934	(77,114)	475,669	161,182	633,327	54,394	0	578,933
2035	2,874,922	992,535	1,277,165	206,934	(77,108)	475,395	161,182	633,053	54,930	0	578,123
2036	2,874,922	992,535	1,277,452	206,934	(77,101)	475,102	161,182	632,760	65,130	0	567,630
2037	2,874,922	992,535	1,277,757	206,934	(77,600)	475,297	161,182	632,955	56,012	0	576,943
2038	2,874,922	992,535	1,278,083	206,934	(77,593)	474,963	161,182	632,621	56,614	0	576,007
2039	2,874,922	992,535	1,278,432	206,934	(77,584)	474,606	161,182	632,264	57,258	0	575,006
2040	2,874,922	992,535	1,278,805	206,934	(77,576)	474,224	161,182	631,882	57,881	0	574,001
2041	2,874,922	992,535	1,279,203	206,934	(77,566)	473,817	161,182	631,475	88,542	0	542,933
2042	2,874,922	992,535	1,279,627	206,934	(79,572)	475,397	161,182	633,055	164,240	0	468,815
2043	2,874,922	992,535	1,280,082	206,934	(86,434)	481,806	161,182	639,464	90,810	0	548,654
2044	2,874,922	992,535	1,280,567	206,934	(88,325)	483,210	161,182	640,868	137,583	0	503,285
2045	2,874,922	992,535	1,281,086	206,934	(93,309)	487,676	161,182	645,334	74,603	0	598,528
2046	2,874,922	992,535	1,281,640	206,934	(94,826)	488,639	161,182	646,297	46,806	0	602,110
2047	2,874,922	992,535	1,282,233	206,934	(94,812)	488,032	161,182	645,690	44,187	0	601,503
2048	2,874,922	992,535	1,282,866	206,934	(94,797)	487,385	161,182	645,043	41,738	0	603,305
2049	2,874,922	992,535	1,283,542	206,934	(94,782)	486,693	161,182	644,351	37,658	0	606,693
2050	2,874,922	992,535	1,284,265	206,934	(94,765)	485,953	161,182	643,611	34,029	0	609,582
2051	2,874,922	992,535	1,285,037	206,934	(94,746)	485,163	161,182	642,821	30,829	0	611,992
2052	2,874,922	992,535	1,285,861	206,934	(94,727)	484,319	161,182	641,977	27,998	0	613,979
2053	2,874,922	992,535	1,286,743	206,934	(94,706)	483,417	161,182	641,075	43,846	0	597,229
2054	2,874,922	992,535	1,287,685	206,934	(94,684)	482,452	161,182	640,110	44,433	0	595,677
2055	2,874,922	992,535	1,288,691	206,934	(94,660)	481,422	161,182	639,080	45,052	0	594,028
2056	2,874,922	992,535	1,289,766	206,934	(94,635)	480,322	161,182	637,980	45,703	0	592,277
2057	2,874,922	992,535	1,290,915	206,934	(94,608)	479,146	161,182	636,804	46,338	0	590,466
2058	2,874,922	992,535	1,292,143	206,934	(94,579)	477,890	161,182	635,548	47,002	0	588,546
2059	2,874,922	992,535	1,293,455	206,934	(94,549)	476,547	161,182	634,205	47,696	0	586,509
2060	2,874,922	992,535	1,295,469	206,934	(96,616)	566,600	161,182	724,258	48,417	0	675,841
2061	2,874,922	992,535	938,411	206,934	(102,892)	839,934	161,182	997,592	49,166	0	948,426
GENERATION TOTALS	204,328,356	59,798,676	107,618,865	13,602,675	5,394,979	17,913,161	10,548,549	28,710,665	10,355,459	729,082	16,223,903

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.
2/MAY INCLUDE ADJUSTMENTS FOR ACCRUAL REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.
3/CONSISTS OF AMORTIZATION (\$1,650) AND DEFERRAL PAYMENT (\$2,760).
4/CONSISTS OF AMORTIZATION (\$1,342) AND DEFERRAL PAYMENT (\$190,952).
5/REDUCED BY \$15,000 OF REVENUE FINANCING.

Table 8A: Generation Revised Revenue Test Income Statement

(\$000s)

	A	B
	2010	2011
1 REVENUES FROM PROPOSED RATES	2,879,557	2,970,605
2 OPERATING EXPENSES		
3 POWER SYSTEM GENERATION RESOURCES		
4 OPERATING GENERATION	566,645	644,193
5 OPERATING GENERATION SETTLEMENT PAYMENT	21,328	21,754
6 NON-OPERATING GENERATION	2,618	2,728
7 CONTRACTED POWER PURCHASES	89,673	74,727
8 AUGMENTATION POWER PURCHASES	180,766	273,043
9 EXCHANGES & SETTLEMENTS	265,558	270,087
10 RENEWABLE GENERATION	45,588	44,638
11 GENERATION CONSERVATION	55,988	55,622
12 CONSERVATION AND RENEWABLE DISCOUNT	28,000	29,500
13 PS TRANSMISSION ACQUISITION AND ANCILLARY SERVICES	187,217	167,091
14 POWER NON-GENERATION OPERATIONS	78,601	81,667
15 F&W/USF&W/PLANNING COUNCIL/ENVIRONMENTAL REQUIREMENTS	248,583	270,714
16 GENERAL AND ADMINISTRATIVE/SHARED SERVICES	65,408	65,643
17 OTHER INCOME, EXPENSES AND ADJUSTMENTS	0	0
18 NON-FEDERAL DEBT SERVICE	565,486	581,494
19 DEPRECIATION	120,111	121,235
20 AMORTIZATION	77,728	85,699
21 TOTAL OPERATING EXPENSES	2,599,297	2,789,835
22 INTEREST EXPENSE:		
23 INTEREST		
24 APPROPRIATED FUNDS	223,278	213,982
25 CAPITALIZATION ADJUSTMENT	(45,937)	(45,937)
26 BONDS ISSUED TO U.S. TREASURY	42,061	58,140
27 AMORTIZATION OF CAPITALIZED BOND PREMIUMS	185	185
28 ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	(10,800)	(10,200)
29 INTEREST CREDIT	(42,404)	(40,854)
30 NET INTEREST EXPENSE	166,383	175,316
31 TOTAL EXPENSES	2,765,680	2,965,151
32 NET REVENUES	113,877	5,454

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

(\$000s)

	A	B
	2010	2011
1 CASH PROVIDED BY OPERATING ACTIVITIES		
2 NET REVENUES	113,877	5,454
3 NON-CASH ITEMS:		
4 DEPRECIATION AND AMORTIZATION	197,839	206,934
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	262,440	163,111
9 CASH USED FOR INVESTMENT ACTIVITIES:		
10 INVESTMENT IN:		
11 FEDERAL UTILITY PLANT (INCLUDING AFUDC)	(259,035)	(271,274)
12 CONSERVATION	(32,819)	(39,592)
13 FISH & WILDLIFE	(70,000)	(60,000)
14 CASH USED FOR INVESTMENT ACTIVITIES	(361,854)	(370,866)
15 CASH FROM AND (USED FOR) FINANCING ACTIVITIES		
16 INCREASE IN TREASURY DEBT	260,400	270,800
17 REPAYMENT OF TREASURY DEBT	(68)	(60,000)
18 INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS	101,454	100,066
19 REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS	(244,605)	(102,163)
20 PAYMENT OF IRRIGATION ASSISTANCE	0	0
21 CASH USED FOR FINANCING ACTIVITIES	117,181	208,703
22 ANNUAL INCREASE (DECREASE) IN CASH	17,767	948

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	162,099	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	135,010	5/	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	773,510	1,436,548	181,878	157,609	304,114	(84,357)	537,237	261,276		275,961
2007	2,657,891	818,494	1,361,837	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	28,438	195,087	277,483	2,950	(85,346)
COST EVALUATION PERIOD											
2009	2,275,866	857,483	1,250,309	181,044	145,785	(158,755)	111,542	8,036	273,159	7,274	(272,397)
RATE APPROVAL PERIOD											
2010	2,879,557	967,502	1,433,956	197,839	166,383	113,877	152,087	262,440	244,673		17,767
2011	2,970,605	983,035	1,599,866	206,934	175,316	5,454	161,182	163,111	162,163		948
REPAYMENT PERIOD											
2012	2,970,605	983,035	1,611,165	206,934	179,264	(9,793)	161,182	147,865	97,948	1,206	48,711
2013	2,970,605	983,035	1,564,965	206,934	188,227	30,445	161,182	188,103	38,900	100,492	48,711
2014	2,970,605	983,035	1,596,807	206,934	191,101	(7,272)	161,182	150,386	15,950	85,726	48,711
2015	2,970,605	983,035	1,567,353	206,934	197,399	15,883	161,182	173,541	32,819	92,012	48,711
2016	2,970,605	983,035	1,644,401	206,934	205,587	(69,353)	161,182	88,305	39,592	0	48,713

Table 9 cont.

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)
2017	2,970,605	983,035	1,674,971	206,934	211,958	(106,292)	161,182	51,366	0	2,650	48,716
2018	2,970,605	983,035	1,500,095	206,934	215,536	65,004	161,182	222,662	145,963	27,989	48,711
2019	2,970,605	983,035	1,020,523	206,934	201,544	558,569	161,182	716,227	609,349	58,168	48,711
2020	2,970,605	983,035	1,118,655	206,934	169,066	492,915	161,182	650,573	576,920	24,943	48,711
2021	2,970,605	983,035	1,118,666	206,934	136,440	525,530	161,182	683,188	622,123	12,354	48,711
2022	2,970,605	983,035	1,118,661	206,934	100,611	561,364	161,182	719,022	655,726	14,585	48,711
2023	2,970,605	983,035	1,119,072	206,934	63,564	598,000	161,182	755,658	693,695	13,252	48,711
2024	2,970,605	983,035	1,161,666	206,934	40,293	578,677	161,182	736,335	672,210	15,414	48,711
2025	2,970,605	983,035	1,275,515	206,934	(11,947)	517,068	161,182	674,726	612,115	13,900	48,711
2026	2,970,605	983,035	1,275,292	206,934	(40,825)	546,169	161,182	703,827	633,963	21,154	48,711
2027	2,970,605	983,035	1,275,449	206,934	(67,506)	572,692	161,182	730,350	436,911	192,572	100,867
2028	2,970,605	983,035	1,275,617	206,934	(83,750)	588,769	161,182	746,427	57,284	0	689,143
2029	2,970,605	983,035	1,275,797	206,934	(83,746)	588,585	161,182	746,243	51,431	0	694,812
2030	2,970,605	983,035	1,275,990	206,934	(83,741)	588,388	161,182	746,046	46,309	0	699,737
2031	2,970,605	983,035	1,276,194	206,934	(83,736)	588,178	161,182	745,836	71,752	0	674,084
2032	2,970,605	983,035	1,276,414	206,934	(85,228)	589,450	161,182	747,108	37,729	0	709,379
2033	2,970,605	983,035	1,276,648	206,934	(85,222)	589,210	161,182	746,868	73,903	0	672,965
2034	2,970,605	983,035	1,276,898	206,934	(86,491)	590,229	161,182	747,887	54,394	0	693,493
2035	2,970,605	983,035	1,277,165	206,934	(86,485)	589,955	161,182	747,613	54,930	0	692,683
2036	2,970,605	983,035	1,277,452	206,934	(86,478)	589,662	161,182	747,320	65,130	0	682,190
2037	2,970,605	983,035	1,277,757	206,934	(86,977)	589,857	161,182	747,515	56,012	0	691,503
2038	2,970,605	983,035	1,278,083	206,934	(86,970)	589,523	161,182	747,181	56,614	0	690,567
2039	2,970,605	983,035	1,278,432	206,934	(86,961)	589,166	161,182	746,824	57,258	0	689,566
2040	2,970,605	983,035	1,278,805	206,934	(86,953)	588,784	161,182	746,442	57,881	0	688,561
2041	2,970,605	983,035	1,279,203	206,934	(86,943)	588,377	161,182	746,035	88,542	0	657,493
2042	2,970,605	983,035	1,279,627	206,934	(88,949)	589,957	161,182	747,615	164,240	0	583,375
2043	2,970,605	983,035	1,280,082	206,934	(95,811)	596,366	161,182	754,024	90,810	0	663,214
2044	2,970,605	983,035	1,280,567	206,934	(97,702)	597,770	161,182	755,428	137,583	0	617,845
2045	2,970,605	983,035	1,281,086	206,934	(102,686)	602,236	161,182	759,894	74,603	0	713,088
2046	2,970,605	983,035	1,281,640	206,934	(104,203)	603,199	161,182	760,857	46,806	0	716,670
2047	2,970,605	983,035	1,282,233	206,934	(104,189)	602,592	161,182	760,250	44,187	0	716,063
2048	2,970,605	983,035	1,282,866	206,934	(104,174)	601,945	161,182	759,603	41,738	0	717,865
2049	2,970,605	983,035	1,283,542	206,934	(104,159)	601,253	161,182	758,911	37,658	0	721,253
2050	2,970,605	983,035	1,284,265	206,934	(104,142)	600,513	161,182	758,171	34,029	0	724,142
2051	2,970,605	983,035	1,285,037	206,934	(104,123)	599,723	161,182	757,381	30,829	0	726,552
2052	2,970,605	983,035	1,285,861	206,934	(104,104)	598,879	161,182	756,537	27,998	0	728,539
2053	2,970,605	983,035	1,286,743	206,934	(104,083)	597,977	161,182	755,635	43,846	0	711,789
2054	2,970,605	983,035	1,287,685	206,934	(104,061)	597,012	161,182	754,670	44,433	0	710,237
2055	2,970,605	983,035	1,288,691	206,934	(104,037)	595,982	161,182	753,640	45,052	0	708,588
2056	2,970,605	983,035	1,289,766	206,934	(104,012)	594,882	161,182	752,540	45,703	0	706,837
2057	2,970,605	983,035	1,290,915	206,934	(103,985)	593,706	161,182	751,364	46,338	0	705,026
2058	2,970,605	983,035	1,292,143	206,934	(103,956)	592,450	161,182	750,108	47,002	0	703,106
2059	2,970,605	983,035	1,293,455	206,934	(103,926)	591,107	161,182	748,765	47,696	0	701,069
2060	2,970,605	983,035	1,205,469	206,934	(105,993)	681,160	161,182	838,818	48,417	0	790,401
2061	2,970,605	983,035	938,411	206,934	(112,269)	954,494	161,182	1,112,152	49,166	0	1,062,986
GENERATION TOTALS	208,831,544	59,371,176	107,618,866	13,602,675	4,965,848	23,272,979	10,548,549	34,070,484	10,359,004	729,082	21,580,177

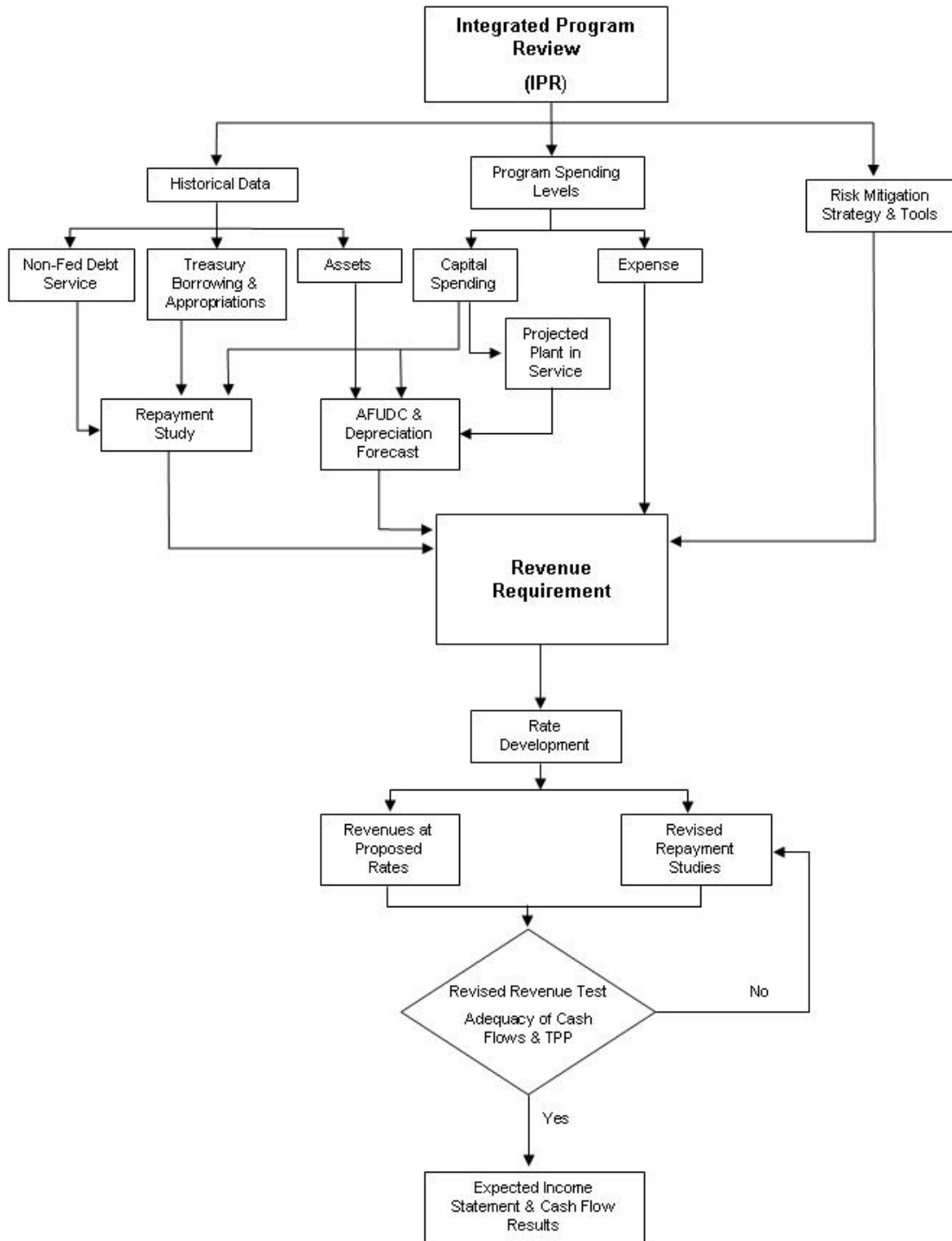
1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.
2/MAY INCLUDE ADJUSTMENTS FOR ACCRUAL REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.
3/CONSISTS OF AMORTIZATION (\$1,650) AND DEFERRAL PAYMENT (\$2,760).
4/CONSISTS OF AMORTIZATION (\$1,342) AND DEFERRAL PAYMENT (\$190,952).
5/REDUCED BY \$15,000 OF REVENUE FINANCING.

Table 10: Amortization of Generation Investments Over Repayment Period

(\$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 Service	Amortization	Unamortized Amount
3	2008	4,094,455	-	4,094,455	-	-	4,094,455	5,311,770	683,690	-	683,690
4	2009	336,473	-	4,430,928	190,690	28,375	4,211,863	5,417,138	-	7,274.00	676,416
5	2010	373,881	-	4,585,744	68	244,605	4,341,071	5,541,434	-	-	676,416
6	2011	383,748	-	4,724,819	60,000	102,163	4,562,656	5,675,065	-	-	676,416
7	2012	-	115,308	4,677,964	92,800	5,148	4,580,016	5,519,342	-	1,206.00	675,210
8	2013	-	107,672	4,687,688	10,000	28,900	4,648,788	5,477,014	-	100,491.65	574,718
9	2014	-	108,064	4,756,852	15,950	-	4,740,902	5,506,554	-	85,725.73	488,993
10	2015	-	108,477	4,849,379	32,819	-	4,816,560	5,462,212	-	92,011.71	396,981
11	2016	-	108,886	4,925,446	39,592	-	4,885,854	5,528,802	-	-	396,981
12	2017	-	109,362	4,995,216	-	-	4,995,216	5,572,038	-	2,649.91	394,331
13	2018	-	109,900	5,105,116	-	145,963	4,959,153	5,636,733	-	27,989.00	366,342
14	2019	-	110,498	5,069,651	40,000	569,349	4,460,302	5,622,459	-	58,168.00	308,174
15	2020	-	111,150	4,571,452	30,000	546,920	3,994,532	5,624,780	-	24,943.00	283,231
16	2021	-	111,854	4,106,386	25,000	597,123	3,484,263	5,627,786	-	12,354.00	270,877
17	2022	-	112,606	3,596,869	-	655,726	2,941,143	5,672,663	-	14,585.00	256,292
18	2023	-	100,236	3,041,379	25,000	668,695	2,347,684	5,574,886	-	13,252.00	243,040
19	2024	-	89,375	2,437,059	40,000	632,210	1,764,848	5,616,993	-	15,414.00	227,626
20	2025	-	79,794	1,844,642	70,000	542,115	1,232,527	5,387,297	-	13,900.00	213,726
21	2026	-	71,349	1,303,876	0	633,963	669,913	5,162,459	-	21,154.00	192,572
22	2027	-	63,909	733,822	-	436,911	296,912	5,115,257	-	192,572.00	-
23	2028	-	57,284	354,196	-	57,284	296,912	4,956,341	-	-	-
24	2029	-	51,431	348,343	-	51,431	296,912	4,750,351	-	-	-
25	2030	-	46,309	343,221	-	46,309	296,912	4,793,546	-	-	-
26	2031	-	41,752	338,664	30,000	41,752	266,912	4,792,946	-	-	-
27	2032	-	37,729	304,641	-	37,729	266,912	4,624,162	-	-	-
28	2033	-	53,903	320,815	20,000	53,903	246,912	4,378,736	-	-	-
29	2034	-	54,394	301,306	-	54,394	246,912	4,433,130	-	-	-
30	2035	-	54,930	301,842	-	54,930	246,912	4,439,846	-	-	-
31	2036	-	55,449	302,361	9,681	55,449	237,231	4,495,031	-	-	-
32	2037	-	56,012	293,243	-	56,012	237,231	4,478,507	-	-	-
33	2038	-	56,614	293,845	-	56,614	237,231	4,516,273	-	-	-
34	2039	-	57,258	294,489	-	57,258	237,231	4,573,531	-	-	-
35	2040	-	57,881	295,112	-	57,881	237,231	4,628,655	-	-	-
36	2041	-	58,542	295,773	30,000	58,542	207,231	4,678,446	-	-	-
37	2042	-	59,240	266,471	105,000	59,240	102,231	4,736,812	-	-	-
38	2043	-	55,810	158,041	35,000	55,810	67,231	4,635,144	-	-	-
39	2044	-	52,583	119,814	85,000	52,583	(17,769)	4,610,940	-	-	-
40	2045	-	49,603	31,834	25,000	49,603	(42,769)	4,559,570	-	-	-
41	2046	-	46,806	4,037	0	46,806	(42,769)	4,564,646	-	-	-
42	2047	-	44,187	1,418	0	44,187	(42,769)	4,539,517	-	-	-
43	2048	-	41,738	(1,031)	0	41,738	(42,769)	4,581,255	-	-	-
44	2049	-	37,658	(5,111)	0	37,658	(42,769)	4,574,913	-	-	-
45	2050	-	34,029	(8,740)	0	34,029	(42,769)	4,522,335	-	-	-
46	2051	-	30,829	(11,940)	0	30,829	(42,769)	4,444,229	-	-	-
47	2052	-	27,998	(14,771)	0	27,998	(42,769)	4,458,300	-	-	-
48	2053	-	43,846	1,077	0	43,846	(42,769)	4,426,560	-	-	-
49	2054	-	44,433	1,664	0	44,433	(42,769)	4,296,732	-	-	-
50	2055	-	45,052	2,283	0	45,052	(42,769)	4,011,527	-	-	-
51	2056	-	45,703	2,934	0	45,703	(42,769)	3,501,412	-	-	-
52	2057	-	46,338	3,569	0	46,338	(42,769)	3,375,012	-	-	-
53	2058	-	47,002	4,233	0	47,002	(42,769)	3,255,796	-	-	-
54	2059	-	47,696	4,927	0	47,696	(42,769)	3,195,428	-	-	-
55	2060	-	48,417	5,648	0	48,417	(42,769)	2,867,441	-	-	-
56	2061	-	49,166	6,397	0	49,166	(42,769)	2,707,655	-	-	-
57	TOTAL	5,188,557	3,256,062		1,011,600	7,475,788					

Figure 1: Revenue Requirement Process



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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,

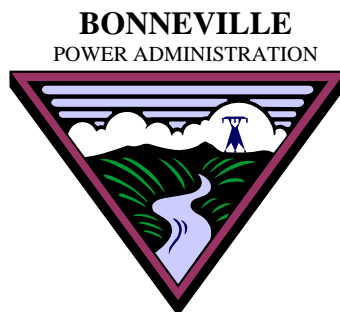
/s/ David J. Armstrong November 14, 2008

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**



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
	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Power Program						
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)

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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
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FY 2010-11 Power Capital Summary

\$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Power Program						
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
	FY 2009	FY 2009	FY 2009	FY 2009	FY 2009
Description					
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
	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
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
	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
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.

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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 the 1970s.

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.

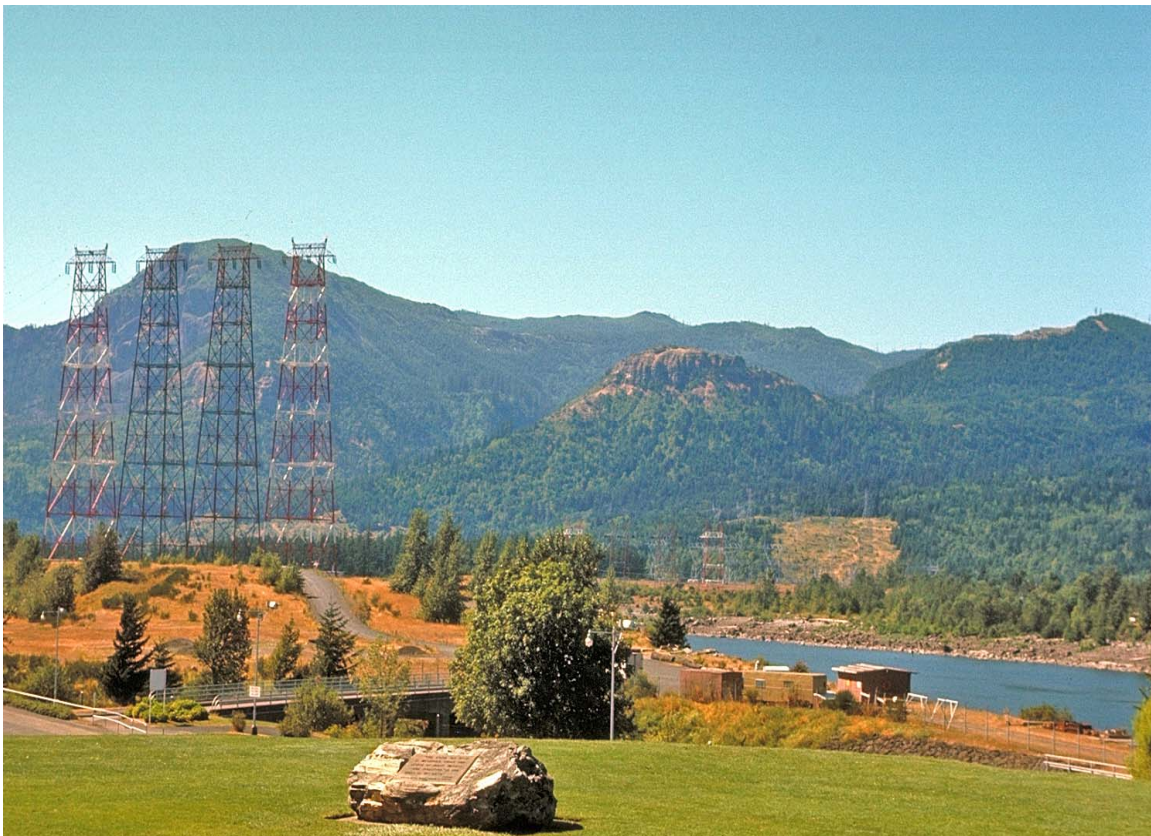
Decision: Changes since the initial IPR numbers reflect the decisions described above related to the decreased Conservation capital for FY 2010 and 2011. Other changes that affect the current estimates are revised estimates of FY 2008 investments and revised reserves estimates resulting in different 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						
	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
Power 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)

*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 leveling 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 led 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.



Department of Energy

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

FINANCE

June 19, 2009

In reply refer to: F-2

To Customers, Constituents, Tribes and Other Regional Stakeholders:

The Bonneville Power Administration (BPA) now brings to a close the second round of the Integrated Program Review (IPR2) for FY 2010-2011 Power and Transmission Costs which began on March 18, 2009. While both Power and Transmission costs are included in the scope of the IPR process, the focus of this IPR2 has been on costs that affect Power rates.

BPA hosted three management-level meetings on March 18, April 9, and April 29, 2009, to hear and collaboratively discuss comments on proposed program spending levels for Power and risk mitigation tools that could be used to keep BPA's FY 2010-2011 power rates as low as possible while continuing to meet key agency objectives. BPA released a Draft Decisions Report on April 24, 2009. Comments on draft decisions were received at the April 29 meeting and during the public comment period held from March 18 through May 4, 2009. BPA appreciates and values the participation and input you have provided during this process.

The purpose of the attached report is to provide BPA's final conclusions about the costs to be included in its FY 2010-2011 power and transmission rate case final proposals based on discussions and comments received. The final program levels identified in the attached report reflect efforts taken by BPA and its partners to address the current deterioration in economic conditions and the difficulty a large BPA Power rate increase would create in the region. Significant reductions in program level forecasts have been identified during the IPR2, including total reductions affecting power rates of \$106 million over the FY 2010-2011 rate period and an additional \$43 million identified in FY 2009.

BPA has reduced planned Agency Services costs by \$19 million and Power Internal Operations costs by \$9.7 million in the FY 2010-2011 period, resulting in a 7 percent reduction in internal costs affecting power. Energy Northwest has confirmed reductions totaling \$11.3 million in FY 2010 and \$40.1 million in FY 2011, primarily from fuel cost reductions and shifting fuel costs out of the FY 2010-2011 period. The Corps of Engineers and Bureau of Reclamation have reduced FY 2010-2011 Operations and Maintenance program level forecasts by \$13.2 million. BPA, in conjunction with several Northwest Tribes, has confirmed \$30 million in reductions to Fish & Wildlife expense forecasts in FY 2009-2010. All of these and other reductions detailed in the attached report will contribute in a major way to our effort to keep the size of the Power rate increase as low as possible.

BPA believes the program levels reflected in the attached report are at an appropriate level given current economic conditions and the need to minimize the size of BPA's Power rate increase in FY 2010-2011. Customers challenged us to find additional cost reductions; however, BPA does not believe it would be prudent to make additional reductions. BPA's capital program is expanding, with the general support of IPR participants, to address increased renewable generation, energy efficiency, and fish and wildlife needs, and to assure reliability of the hydroelectric and transmission systems. To successfully achieve this planned capital program, adequate internal infrastructure must be in place. Additionally, regulatory requirements and environmental obligations have increased in recent years. These all put significant pressure on BPA expenses as well as capital. BPA believes making reductions in addition to the already significant reductions would jeopardize BPA's ability to meet key strategic objectives and responsibilities.

The reductions being put in place here reflect the near term stresses as a result of the combination of (1) the calamitous global, national and regional economic downturn, and (2) substantially reduced 2009 BPA revenues as a result of poor water and market conditions. These events have resulted in an imperative to focus on near term rates. Should there be recovery from either of these factors in the FY 2010-2011 period, BPA may consider restoring some of these reductions.

Thank you very much for your attention and input to the Integrated Program Review for FY 2010-2011 Power and Transmission costs. For further information on the IPR2 or other issues, please contact your customer account executive, constituent account executive, tribal account executive, or me at (503) 230-5111. Additional information on the process is available at <http://www.bpa.gov/corporate/Finance/IBR/IPR/>.

Sincerely,

/s/ David J. Armstrong

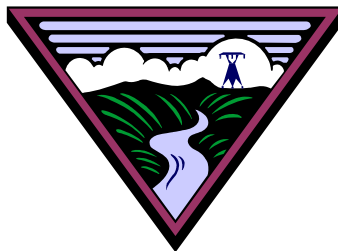
David J. Armstrong
Executive Vice President and Chief Financial Officer

Enclosure
IPR2 FY 2010-2011 Power and Transmission Program Levels Final Report

**Bonneville Power Administration
Integrated Program Review 2
FY 2010-2011 Power and Transmission Program Levels**

**Final Report
June 19, 2009**

**BONNEVILLE
POWER ADMINISTRATION**



Final Report for Integrated Program Review 2

FY 2010-2011 Power and Transmission Program Levels

SECTION 1: BACKGROUND AND SUMMARY OF DECISIONS

Background

BPA held its first “Integrated Program Review” (IPR1) process in 2008. The IPR1 largely focused on FY 2010 and 2011 program levels for BPA’s Power and Transmission Services. Results of that process were made public November 14, 2008, in a report that addressed the comments received and outlined BPA’s decisions regarding the FY 2010-2011 program level forecasts. (See www.bpa.gov/corporate/Finance/IBR/IPR/ for additional background and the materials made available during that process). While these expense and capital forecasts formed the basis for Power and Transmission rate case initial proposals for FY 2010-2011 rates, BPA committed to re-evaluating those costs in an additional public process prior to the development of final rate proposals in the spring of 2009.

The Spring Process

BPA held the Integrated Program Review 2 (IPR2) workshops to review spending level decisions made in November 2008. The IPR2 was expected to be abbreviated; however several factors have changed the landscape significantly since the IPR1 and development of the initial rate proposals released in February. The global financial market crisis and the deterioration of the U.S. economy have resulted in high unemployment and severe financial circumstances for many in the Northwest. At the same time, BPA’s financial situation declined due to continuing poor hydro conditions and low power market prices, resulting in the potential for a significant increase in power rates for FY 2010-2011. Because BPA recognizes it would be very difficult for the Pacific Northwest to tolerate a large power rate increase in the current economic climate, in the Power rate case, BPA has been working collaboratively with customers to identify risk mitigation tools to decrease the likelihood of a significant rate increase. Likewise, in the IPR2 process, BPA, the U.S. Army Corps of Engineers (Corps), the Bureau of Reclamation (Reclamation), and Energy Northwest (EN) have been working collaboratively to identify potential areas of targeted cost-reduction measures to help keep power rates down. While this IPR2 process is focused on FY 2010-2011, forecasted reductions have also been found in some programs for FY 2009, and are described in this document. These reductions affect the ending FY 2009 cash reserves which can have an impact on power rates in the subsequent rate period.

Three workshops were held in March and April. At the first workshop on March 18, BPA presented an initial set of proposed program levels with little change from the original IPR1 decisions, but discussed the fact that additional actions would be needed to avoid a potentially large power rate increase and that BPA and its partner agencies were in the process of assessing what additional actions they could take to reduce costs. Participants at the meeting heard from utility general managers that they are seeing severe economic impacts to their customers, they are taking severe cost-cutting actions, and they expect BPA, EN, the Corps, and Reclamation to do the same.

A second workshop was held on April 9 to provide a status update on cost reduction efforts. At that meeting, BPA described the efforts it had taken to reduce FY 2009 forecasted operating costs by about \$18 million or 2.7 percent, roughly \$6.3 million of which is recovered in power rates. The remaining \$11.7 million will impact Transmission expense and capital costs. These reductions include elimination of certain employee and executive monetary performance awards, totaling approximately \$6.8 million, for the remainder of FY 2009. BPA also described the efforts in progress to reduce FY 2010-2011 forecasted operating costs recovered through power rates by roughly 7 percent. Fish and Wildlife reductions were not yet identified, but BPA indicated that spending levels for meeting new Columbia Fish Accord commitments this year and next are likely to be less than anticipated in the current IPR2 materials. The Corps, Reclamation and EN described their progress on identifying proposed cost reductions: the Corps identified \$3.7 million in reductions over the FY 2009-2011 period; Reclamation identified \$2.3 million reduction in FY 2011; and EN identified potential fuel cost reductions of \$6.8 million in FY 2009 and \$12 million in FY 2010, in addition to the changes related to uranium purchases identified at the March 18 meeting, and expected to find additional reductions. While customers expressed appreciation for the work to date, they encouraged the agencies to find additional reductions. BPA, the Corps, Reclamation and EN all committed to review their forecasts again.

Since that time, BPA confirmed its 7 percent FY 2010-2011 internal cost reductions and decreased the forecasts for Fish and Wildlife spending due to the timing associated with ramping up the program. EN committed to additional fuel cost reductions, and the Corps and Reclamation identified additional O&M cost reductions since the April 9 meeting. These reductions were described in the final IPR2 workshop held on April 29, 2009.

The period to provide comment in this process closed May 4. This document describes the program levels that will be used in the FY 2010-2011 rate cases and how they have changed from the original IPR1 assumptions and addresses comments received during the comment period.

Summary of Program Level Changes

BPA recognizes the serious impact a large power rate increase could have on the region in the current economic downturn. While BPA believes the proposed spending levels identified in the IPR1 process were appropriate and prudent from both a long- and a short-term perspective under normal conditions, BPA executives determined that it is important that the Agency take additional cost-reduction actions to reduce the increase to power rates in light of the adverse economic conditions in the Region. They asked that all parts of the agency whose costs impact power rates reduce their internal operations costs below the levels identified in the earlier IPR1. However, should economic conditions and/or BPA's financial conditions improve during the rate period, BPA may consider restoring some of these reductions to improve its ability to meet its objectives.

Significant reductions in cost forecasts have resulted during this IPR2. In total, power cost reductions totaling \$106 million over the FY 2010-2011 rate period have been identified, averaging about \$53 million per year. Another \$43 million in power cost reductions were identified for FY 2009. These reductions do not include potential reductions to depreciation and interest expense. These reductions will make a major contribution to the effort to reduce the size of the potential Power rate increase.

As BPA reviewed planned spending levels in this IPR2 process, the primary emphasis was on reducing proposed costs that impact Power rates. The forecasted reductions are summarized here, and are described in more detail in the sections following.

- Internal cost reductions impacting Power rates (including the result of reductions in both Power Internal Operating costs and Agency Services costs allocated to Power) are \$2.3 million for FY 2009, \$9.6 million for FY 2010, and \$12.0 million for FY 2011. This represents a 7 percent reduction in internal costs that affect power rates.
- The Corps reduced their spending level forecast for FY 2010-2011 by \$7.4 million, they also reduced FY 2009 costs by \$2.6 million.
- Reclamation reduced their spending level forecast for FY 2010-2011 by \$2.8 million. They also reduced their FY 2009 costs by \$810 thousand.
- BPA, in coordination with the Columbia River Inter-Tribal Fish Commission (CRITFC), has updated the anticipated spending levels for meeting new Columbia Fish Accord commitments in FY 2009 and FY 2010, and is forecasting \$15 million per year less spending as a result of new work in the Fish Accords not ramping up as quickly as expected.
- EN costs have been reduced by a total of \$11.3 million in FY 2010 and \$40.1 million in FY 2011. \$28.2 million of this two year reduction is related to a uranium fuel purchase made in FY 2009, which increases FY 2009 costs but results in lower over-all fuel costs over the rate period and the three-year period FY 2009-2011. Additionally, EN committed to O&M reductions of \$800,000 in 2010 and 2011 and to making an additional \$11 million reduction either through fuel cost reductions or non-fuel O&M cost reductions.
- Long-term Generating Program costs have been reduced by \$1.4 million in FY 2010 and \$1.6 million in FY 2011 due to new analysis of the likely costs.
- Conservation changes net a \$1.5 million decrease in FY 2010 and no change in FY 2011.
- Technology Innovation Research and Development costs have been reduced by \$2.6 million for FY 2011.
- “Other” Power costs have been reduced by \$1.8 million in FY 2010 and \$3.6 million in FY 2011, reflecting the decision to not pursue the Flexible PF Rate Program in those years.

Potential Increased Wind Integration Costs

As BPA continues to analyze what spending will be required to provide the integration necessary for the many planned wind projects in the region, it is becoming apparent that internal system and staffing costs related to that integration may be higher than reflected in the program levels presented in this report. This may put unexpected cost pressures on BPA during the FY 2010-2011 rate period. BPA is unable to know at this time what the necessary costs will be, though they are not expected to exceed \$10 million per year. BPA is working to determine the requirements and as they become more clear, BPA will provide information to stakeholders. No additional costs have been included in program levels at this time.

Summary of General Comments Received

- Cost reductions:
 - Central Lincoln PUD noted that a change between 2010 and 2011 rates of 9.4% is steep. Further cuts should be taken to get to no more than a 5% increase year-to-year.
 - Multiple parties recommended that BPA should be reviewing all costs and expenses at this time to avoid a rate increase.
 - Public Power Council (PPC), Pacific Northwest Generating Cooperative (PNGC Power), Benton Rural Electric Association, Umatilla Electric Company and Springfield Utility Board believe more needs to be done in the area of cost reductions that further reduce or eliminate the need for a wholesale power rate increase.
 - Snohomish PUD thanks BPA for re-examining its own programs and those of its business partners; this process has been fruitful in minimizing the upcoming rate increase. Snohomish also urges BPA to examine its internal costs on an ongoing basis, and asks that in future IPR processes BPA explicitly tie program activity and subsequent budget changes, both increases and decreases, to BPA's long-term strategic plan.
 - A private citizen recommended that anyone working at BPA making more than \$65,000 a year should have their wages decreased by 20% and anyone making more than \$100,000 a year decreased by 25% and anyone serving as a volunteer should not be paid at all.

Response: BPA and its partner agencies have found significant reductions in planned costs for FY 2009-2011. BPA does not believe it would be prudent to make additional reductions. Participants in this process have been generally supportive of BPA's proposed expansion of the capital program in support of energy efficiency, renewable generation, fish and wildlife responsibilities, economic stimulus, and assuring the long-term reliability of both the hydroelectric and transmission systems. A capital program of this magnitude requires an internal infrastructure that supports that program, which puts pressure on expenses. Increasing regulatory compliance requirements and the increasing complexity of the business environment all put tremendous pressure on expense and capital programs. BPA and its partners have identified significant reductions from otherwise prudent program levels to minimize the power rate increase and its impact on the regional economy. BPA believes further cuts could jeopardize its ability to meet key strategic objectives and responsibilities.

Comments on Issues Other than Costs

- There were several comments related to Stepped Rates.
- Multiple parties recommended that BPA should stop serving DSIs.
- Snohomish PUD believes that a rate increase of no more than 5.0% should be achievable given the cost reductions of \$50 million and expanded short-term borrowing authority.

Response: Comments regarding Stepped Rates, the level of power rates, and service to the DSIs will be addressed in the ongoing rate case and the ongoing DSI service decision process.

Changes to FY 2009 Power Costs

These are not within the scope of the IPR2 process, but reductions have been targeted in many programs in the current year in order to help mitigate the potential rate increase for the FY 2010-2011 period.

Table 1
Changes in FY 2009 Power Costs from SOY

PROGRAM	SOY	Revised Spending Levels	Change
	FY 2009	FY 2009	FY 2009
	\$ in thousands		
Power			
Columbia Generating Station	293,450	296,000	2,550
Corps and Reclamation	261,600	258,205	(3,395)
Long Term Generation Program	31,613	31,961	348
Renewable Resources includes Rate Credit	41,504	41,504	-
Conservation	82,710	67,910	(14,800)
Internal Operations 1/	122,924	120,673	(2,251)
Fish & Wildlife	200,000	185,000	(15,000)
Other-Colville Settlement, Non-Op Generation	27,413	17,223	(10,190)
Total	1,061,214	1,018,476	(42,738)

1/ Internal Operation costs include both Power Services and Agency Services Internal Operating Costs.

Table 2
Changes in FY 2010-2011 Power Costs from IPR1

	IPR1		Final IPR2 Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
	\$ in thousands					
Power						
Columbia Generating Station	269,200	365,000	257,900	324,900	(11,300)	(40,100)
Corps and Reclamation	280,700	296,461	278,528	288,543	(2,172)	(7,918)
Long Term Generation Program	31,889	32,343	30,455	30,767	(1,434)	(1,576)
Renewables includes Rate Credit	45,588	45,938	45,588	44,638	-	(1,300)
Conservation	87,088	86,722	85,588	86,722	(1,500)	-
Internal Operations 1/	135,627	139,910	127,272	130,425	(8,355)	(9,485)
Post-Retirement Contribution	15,598	16,071	15,447	15,579	(151)	(492)
Fish & Wildlife	263,583	270,714	248,583	270,714	(15,000)	-
Other-Colville Settlement, Non-Op Generation	25,746	28,082	23,946	24,482	(1,800)	(3,600)
Total	1,155,019	1,281,241	1,113,307	1,216,770	(41,712)	(64,471)

1/ Total Reductions to internal costs are \$9.6 million for FY 2010 and \$12.0 million for FY 2011. Note that the reduction amounts shown here appear to be smaller than reported in the April 24th draft decisions report. This is due to a more accurate display of where the April 24th proposed reductions will impact Power programs. **Some of these reductions are now reflected in other power programs rather than in the Internal Operations line on the Power income statement.**

FY 2010-2014 Power Capital Forecasts

No comments were received nor were any changes made to the proposed Power Capital program levels proposed for FY 2010-2014 in BPA's initial IPR2 estimates.

PROGRAM \$ in thousands	IPR1		Final IPR2 Decisions				
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
Power Capital							
Corps and Reclamation*	183,200	199,200	185,000	201,000	198,000	210,000	212,000
Fish & Wildlife	70,000	60,000	70,000	60,000	50,000	50,000	50,000
Conservation*	38,000	46,000	39,000	47,000	56,000	56,000	56,000
CGS	73,600	99,900	70,000	91,130	51,500	50,000	32,000
CRFM	88,000	96,000	101,454	100,066	75,264	190,643	66,224
Lapse Factor	(36,150)	(38,550)	(33,600)	(37,200)	(39,900)	(41,700)	(42,000)
Total	416,650	462,550	431,854	461,996	390,864	514,943	374,224

*15% Lapse factor is applied to the Corps and Reclamation and Conservation Investment. It does not apply to CGS, Fish and Wildlife or CRFM. The lapse factor is an assumption that a percentage of planned capital investment will be delayed into the subsequent rate period.

Table 3
Changes in FY 2010-2011 Transmission Costs from IPR1

	IPR1		Final Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
\$ in thousands						
Transmission						
Operations						
System Operations	56,573	57,497	56,544	57,468	(29)	(29)
Scheduling	9,423	9,868	9,423	9,868	-	-
Marketing	19,500	20,225	54,188	55,132	(2,900)	(2,937)
Business Support	37,588	37,844	included in Marketing			
Maintenance						
System Maintenance	122,099	126,877	121,810	126,577	(289)	(300)
Environmental Operations	3,797	3,996	3,797	3,996	-	-
Transmission Engineering	26,500	28,011	25,240	25,448	(1,260)	(2,563)
Agency Services	58,779	58,940	48,937	49,110	(9,842)	(9,830)
Post-Retirement Contribution	15,598	16,071	15,447	15,579	(151)	(492)
Other Income, Expenses and Adjustments	(2,000)	(2,000)	(2,000)	(2,000)	-	-
Total 1/	347,857	357,329	333,386	341,178	(14,471)	(16,151)

1/ The reduction from IPR1 to the Final Decisions shown here is greater than the amounts included in the Draft Final Report. The reductions in the Draft Report reflected estimates of changes due to Agency Services costs reductions (including the allocation of those reductions) and internal operations reductions. The reduction amounts here have been updated to reflect the correct savings and allocation amounts.

FY 2010-2011 Transmission Capital Forecasts

No comments were received nor were any changes made to the proposed Transmission Capital program levels proposed for FY 2010-2014 in the initial IPR2 estimates.

PROGRAM \$ in thousands	IPR1		Final IPR2 Decisions				
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
Transmission Capital							
Main Grid Projects	150,587	209,346	178,167	189,939	315,384	217,709	174,058
Area & Customer Service Projects	31,714	6,256	31,714	6,256	6,322	7,516	16,814
Upgrades & Additions	95,710	112,585	95,710	112,585	69,009	55,807	57,954
System Replacement Projects	134,494	138,423	134,494	138,423	109,335	114,660	96,445
Environmental Projects	5,530	5,752	5,530	5,752	5,869	5,984	6,101
Customer Financed Credits	90,164	102,286	90,164	102,286	83,904	72,742	74,070
Total Indirect Capital	87,443	96,243	96,273	105,098	110,402	108,052	108,484
Lapse Factor	(100,249)	(103,773)	(105,117)	(109,902)	(104,009)	(86,620)	(79,339)
Total	495,393	567,118	526,935	550,437	596,216	495,850	454,587

Table 4
Agency Services Internal Operations Changes (reflected in the Power and Transmission tables)

PROGRAM	Changes from FY 2009 SOY	FY 2009	Changes From IPR1	FY 2010	Changes from IPR1	FY 2011
Agency Services						
Executive Office	(221)	4,425	(511)	4,423	(11)	3,005
Chief Risk Officer	(145)	5,722	(358)	6,893	(358)	6,854
Technology Innovation	(72)	2,566	(8)	2,064	(8)	2,066
Agency Compliance & Governance	(128)	3,590	(276)	3,604	(276)	3,772
Chief Public Affairs Office	(365)	17,075	(630)	17,476	(615)	18,070
Internal Audit	(87)	2,297	(19)	2,335	(19)	2,337
Finance	(559)	14,411	(1,049)	14,580	(1,049)	15,058
Corporate Strategy	(2,833)	5,987	(2,527)	7,742	(2,527)	8,286
General Counsel	(132)	9,373	(154)	9,489	(156)	9,812
Customer Support Services	(401)	10,539	(900)	10,878	(723)	11,289
Internal Business Services						
Administration, Security and Safety	(297)	10,045	(451)	10,590	(1,807)	11,098
Human Capital Management	(448)	15,780	305	17,149	1,102	17,344
Supply Chain Services	(607)	17,712	(162)	20,958	(166)	20,720
Workplace Services	(599)	29,610	(48)	44,758	(48)	47,213
Information Technology	(1,299)	56,876	(311)	67,935	(311)	67,547
Undistributed Reduction 1/	2,967	0	(1,200)	(1,200)	(1,500)	(1,500)
Estimated Impact of COLA Assumption Reduction 2/	0	0	(1,285)	(1,285)	(1,099)	(1,099)
Agency Services Internal Operations Total	(5,226)	206,008	(9,584)	238,389	(9,571)	241,872
Agency Services Allocated to Power	(1,958)		(3,987)		(4,210)	
Agency Services groups included in Power						
Energy Efficiency & Conservation	(357)	10,772	(580)	9,442	(580)	10,076
Technology Innovation	0	0	0	4,963	(1,300)	4,734
Environment, Fish & Wildlife	(1,411)	11,753	(629)	11,994	(629)	12,946
Total	(3,726)		(5,196)		(6,719)	

1/ A portion of FY 2009 reductions were used to eliminate an undistributed reduction included in the Start-of-Year (SOY) budget.

2/ The COLA reduction for FY 2010 and FY 2011 is an estimated savings at the agency level and is not included in Agency Services organizational budgets.

FY 2010-2014 Agency Services Capital Forecasts

No comments were received nor were any changes made to the proposed Agency Services Capital program levels proposed for FY 2010-2014 in the initial IPR2 estimates.

PROGRAM \$ in thousands	IPR1		Final IPR2 Decisions				
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2012	FY 2013	FY 2014
Agency Capital							
Finance	847	874	847	874	897	924	953
Security & Emergency Mgmt	5,102	5,814	5,102	5,814	5,948	6,005	6,386
General Counsel	148	155	148	155	160	166	172
Workplace Services	60,904	23,741	60,904	23,741	23,858	23,977	24,099
Information Technology	21,375	21,375	21,375	21,375	21,375	21,375	21,374
Total	88,376	51,959	88,376	51,959	52,238	52,447	52,983

SECTION 2: INTERNAL COSTS

Agency Services includes 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.

Proposed Changes:

The total reductions for internal costs impacting Power rates, including reductions in both Power internal operating costs and Agency Services costs allocated to Power, are \$2.3 million for FY 2009, \$9.6 million for FY 2010, and \$12.0 million for FY 2011. This represents a 7 percent reduction in internal costs that affect power rates.¹

- \$9.6 million includes the \$8.4 million Internal Operation reductions in FY 2010 and an additional \$1.25 million internal cost reduction displayed in Fish & Wildlife and Conservation Programs.
- \$12.0 million includes the \$9.5 million Internal Operation reductions in FY 2011, an additional \$1.3 million reduction reflected in Renewable Resources, and \$1.25 million shown in Fish & Wildlife and Conservation.

Agency Services

BPA reduced Agency Services costs by roughly 2 percent or \$5.2 million for FY 2009. Reductions for FY 2010-2011 are roughly 7 percent or \$9.6 million per year for FY 2010-2011. This reduces costs in Power rates by roughly \$4.0 million per year (See Table 4). In addition, given the current economic pressures in the region, it was decided to reduce the Technology

¹ The reduction amounts shown here appear to be smaller than reported in the April 24th Draft Report, due to displaying the reductions more accurately, in the appropriate programs they impact. In other words, not all internal cost reductions appear on the "Internal Operations" line on the Power income statement. For example, reductions to internal costs for the Conservation program are now represented in that program. Also note that since IPR1 estimates were developed, the operating costs of the residential exchange were moved from the residential exchange program to internal operations.

Innovation program for FY 2011 to the FY 2010 level, a \$2.6 million reduction, \$1.3 million of which goes to Power.

Organizations in Agency Services plan to achieve these reductions by:

- Re-prioritizing work.
- Cutting non-time-critical projects.
- Reducing both replacing Bonneville staff and adding contract staff.
- Reducing training and travel.
- Eliminating awards for the remainder of FY 2009 and planned spending for Team Share and Success Share awards in FY 2010 and 2011.
- Reducing the forecast of annual pay increases for FY 2010-2011 from 3.5 percent to 2 percent in FY 2010 and 2.25 percent in FY 2011 due to lower inflation rates (actual increases will be determined at the national level).

Given the difficult economic conditions regionally and nationally, BPA believes it is reasonable to take the above planned actions at this time to reduce its internal cost levels for FY 2010-2011. Note that decreases to Agency Services costs are passed on to Power and Transmission rates through allocations, based on the nature of the agency services activities. In many areas the larger proportion goes to Transmission.

Power Services Internal Costs

Power Services internal costs were reduced by \$0.7 million or 2 percent for FY 2009. Power Services costs are also reduced by approximately 7 percent in FY 2010-2011, \$4.4 million for FY 2010 and \$5.3 million for FY 2011. The reductions for FY 2010 and FY 2011 include a shift of the operating costs of the Residential Exchange program to internal operations totaling \$3.9 million.

Some of the actions planned to achieve these reductions are:

- Reduced planned staffing for Regional Dialogue implementation through power scheduling process efficiencies and expectations of reduced BPA and customer resource acquisition.
- Reduced contract support for Residential Exchange Program and other programs
- Reduced travel.
- Agency-level decisions to reduce planned awards and to use lower forecast of increases to pay rates, due to lower inflation rates.
- Change in Post-Retirement Contribution forecast of expenses updated to reflect changes in the forecasted staff levels, slower employee retirements and a slower rate of growth of health care costs than previously forecasted.

Changes to FY 2009

The planned reduction to Agency Services FY 2009 costs is \$5.2 million or 2.3 percent from the start-of-year budget. Power Services forecasted reduction for 2009 is \$0.7 million or 2.0 percent.

Comments Received:

- PNGC Power noted BPA deserves credit for actions to reduce or eliminate costs. They encourage BPA to seek additional program costs reductions in its Internal Operations. The recommended 7% reduction to Internal Operations in FY 2010-11 is very conservative; PNGC believes a 12% reduction should be implemented while maintaining the currently acceptable level of program activity. At the very least, BPA should look at deferring costs out of the current rate period.
- Benton Rural Electric Association suggested Agency reductions should be at least 8%, double the savings of EN.
- The PPC believes BPA has not justified the need to assume an increase in program activity for the upcoming rate period, therefore the PPC recommends that BPA limit the increase in power services internal operations costs to no more than an assumed 2.5% annual rate of inflation– requiring an additional \$2 million reduction for the FY 2010-2011 rate period.

Decision: BPA believes its internal costs established in the IPR1 process were the appropriate levels to accomplish the Agency’s mission. However the Agency has identified significant reductions in the FY 2009 and FY 2010-2011 forecasts of internal costs in order to minimize an increase in power rates. The acceptable levels of reductions were determined by looking at each program rather than setting an across-the-board percentage reduction level. BPA does not believe it would be prudent to set arbitrary targets for reductions without consideration of the impact on BPA’s ability to meet its key strategic objectives and responsibilities. No additional reductions will be taken because planned reductions beyond the levels proposed here would seriously jeopardize the organization’s ability to support key Agency initiatives.

SECTION 3: POWER SERVICES COSTS, OTHER THAN INTERNAL**A. ENERGY NORTHWEST – COLUMBIA GENERATING STATION**

BPA pays the costs of EN's Columbia Generating Station (CGS) nuclear power plant. EN has continued to focus on mitigating equipment obsolescence, maintaining reliability and improving plant performance. EN management believes continued additional investments are necessary to maintain or improve safety, reliability and performance. The plant’s performance indicators have been low when measured against industry benchmark criteria.

Proposed Changes:

- All changes are described in terms of the impacts in BPA fiscal years rather than EN fiscal years.
- Due to favorable uranium market conditions, EN made uranium purchases in FY 2009, reducing costs in FY 2010-2011. This reduces forecasted O&M costs by \$28.2 million over the rate period but increases costs by \$18.0 million in FY 2009.
- EN has determined that its current Separative Work Unit (SWU) inventory, which is one component of CGS's nuclear fuel inventory, is in excess of CGS's needs and will be sold in EN FY 2011. The excess is the result of the ARTS/MELLA project which reduced CGS's fuel needs and will produce \$12.0 million in revenue that will offset O&M funding needs for CGS.
- Uranium purchases in EN FY 2011 and 2012 will be reduced by \$10.8 million to achieve the \$11.8 million budget reduction commitment. The purchases have been

deferred to future fiscal years, though EN committed to seek to find O&M reductions in lieu of the fuel purchase delay in 2011.

- An error in the original IPR1 forecasts was corrected which increases the forecast by \$4.7 million over the rate period.
- EN and BPA negotiated a reduction to CGS O&M contingency reserves that is different than what was reflected in IPR1 forecasts. This reduces forecasted O&M costs by \$3.9 million over the rate period.
- Nuclear Electric Insurance Limited (NEIL) insurance expense is expected to increase by \$0.8 million over the rate period due to reduced member distributions from NEIL that in the past were used to reduce the gross insurance premiums. This is a smaller increase than the \$1.7 million reflected in the April 24 Draft Report. The member distributions were reduced due to lower investment returns on the NEIL insurance financial reserves and a substantial claim loss in 2008 paid to another plant.
- EN has committed to O&M reductions of \$1.0 million over the rate period to achieve the \$11.8 million. Reductions will be made in travel, training, employee awards, the regional communications plan, and vehicle purchases.
- Other changes to O&M that both increased and reduced CGS funding needs result in an additional \$1.0 million reduction.

Comments Received:

- PNGC Power noted EN deserves credit for actions to reduce or eliminate costs. They also encourage EN to seek additional program costs reductions and commit to operate at reduced cost for each year of the rate period.
- The PPC noted that EN deserves to be commended for their responsiveness to this economic downturn and for identifying an average of \$26 million per year in expense reductions. CGS has done a good job living within the FY 2010 budget set as part of the EN Long Range Plan for CGS in the FY 2009 budget process.
- The PPC also noted they are not in a position to question an increase of 30 FTE to fulfill staffing requirements resulting from various NRC fatigue orders, but looks forward to seeing the analysis EN performs to determine whether a headcount reduction in the near future is achievable.
- The PPC is concerned the scheduled outage may not be completed within the time period assumed in the ratemaking process, therefore BPA should be including a risk factor for unplanned outages at CGS in its risk modeling.

Decision: Spending levels will be reduced by \$11.3 million for FY 2010 and \$40.1 million for FY 2011.

B. CORPS AND RECLAMATION O&M

BPA works with the Corps and the 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 hydro system equipment refurbishments and enhancements.

	IPR1		Final IPR2 Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
\$ in thousands						
Power						
Corps of Engineers	193,000	197,911	191,060	192,433	(1,940)	(5,478)
Bureau of Reclamation	87,700	98,550	87,318	96,110	(382)	(2,440)
Corps and Reclamation	280,700	296,461	278,378	288,543	(2,322)	(7,918)

Proposed Changes:

- The Corps and Reclamation have reduced routine or base program funding by limiting travel and training, reducing materials and supplies purchases, and instituting limited hiring freezes. The Corps reduced its base program by \$1 million in FY 2009, \$2 million in FY 2010, and \$2 million in FY 2011. Reclamation reduced its base program in FY 2009 by \$245 thousand, and by \$940 thousand in FY 2010. In addition to the actions already noted, Reclamation made additional reductions by deferring replacement maintenance at the Roza, Chandler and Green Springs powerplants.
- Funding of performance awards for FY 2009 is included in FY 2010 program levels. This is a change over the costs included in the April 24 Draft Report resulting in a \$.5 million increase for both Corps and Reclamation for FY 2010. The Corps and Reclamation had made commitments to employees and unions, so this funding recognizes that commitment. BPA, the Corps, and Reclamation plan to limit awards for FY 2010 performance (to be paid in FY 2011) to safety related awards similar to BPA's, and the agencies are reviewing our ability to place more flexible language in all future annual awards funding agreements to allow such funding to be more responsive to poor fiscal conditions.
- Reductions were made in funding for Willamette BiOp Studies by the Corps. Since the study plan for the Willamette BiOp is still being developed, the Corps has reduced the forecasted expenses associated with it until refined estimates associated with a more detailed development schedule are completed, and decisions on costing of the studies (expense vs. capital) are made. Reductions total \$4.5 million for the FY 2009-2011 period.
- Reductions in non-routine extraordinary maintenance funding have been made for both the Corps and Reclamation O&M programs.
- The Corps has incorporated the high priority American Recovery and Reinvestment Act (ARRA) joint non-routine maintenance items (mostly spillway gates) into the budget as noted in the April 9 IPR2 meeting, and reduced or deferred power non-routine maintenance to stay within IPR2 program levels.
- Reclamation's reduced IPR2 final funding level does not include non-routine maintenance funding for repairing significant forced outages, particularly associated with the big units in the third powerhouse.
- Also, as noted in the IPR2 process, the amount of work required to keep Grand Coulee operating at a reliable level while preparing for the rehabilitation of the big generating units in the Third Power Plant has increased significantly over what was required in the past. To address this issue, as well as deal with the additional requirements of preparing for the rehabilitation of the Third Power Plant, Reclamation plans to hire temporary workers and/or contractor(s), and will need an additional \$1.5 million per year in FY 2010 and 2011. Some of this funding will be used to return units G19 (derated by 130 MWs) and G9 (derated by 35 MWs) to their full capacity (thereby offsetting these costs with revenue), as well as for other non-routine maintenance activities (such as the

significant leakage in units G19, G20, and G21). Because of this, Reclamations funding levels have been increased by \$1.5 million over the levels presented in the April 24th Draft Decisions Report. This additional funding of \$1.5 million per year for FY 2010 and 2011 will allow Grand Coulee to catch up on required maintenance while focusing on continued reliable operation of the facility, and to properly prepare for the upcoming rehabilitation of the Third Power Plant.

This overall level of reduced funding may require the Corps and Reclamation to request additional funding in the future, depending on the frequency and severity of additional unit forced outages, or if decisions on costing of either studies for the Willamette BiOp or Leavenworth Hatchery BiOp-related work determines that these activities are expenses and not capital.

Comments Received:

- PNGC noted the Corps and Reclamation deserve credit for actions to reduce or eliminate costs. They encourage the Corps and Reclamation to seek additional program cost reductions and to commit to operate at reduced cost for each year of the rate period.
- The PPC continues to support the programmatic approach developed by the Corps, Reclamation and BPA and would like to see ongoing use and improvement of that program. The Corps and Reclamation are encouraged to accomplish all of the cost reductions they have identified and to consider additional cost reductions or cost deferrals into future periods.
- While the Grand Coulee Project Hydroelectric Authority (GCPHA) agrees the hydro projects need significant investment, the limited reductions proposed in the draft program do not respond to the major decline in the economy of the Pacific Northwest. Additionally, it is unlikely that Reclamation and the Corps will be able to accomplish the expense and capital programs proposed. They recommend that BPA critically review the plans for this rate period and the longer term. The major work planned for Grand Coulee needs more careful analysis and planning to be sure that the Right and Left Power Plants are in condition to assume the role of filling in for an extended outage of a Third Power Plant (TPP) unit and that this outage pattern can be extended for nearly a decade in order for all six units in the TPP to undergo major rehab work.
- The GCPHA also noted there are small amounts of flexibility remaining in the hydro system that the Corps and Reclamation retain based on historical practice rather than actual need. The Administrator needs to ask the Division Commander and Regional Director for assistance in this area to assure that the full capability of the system beyond meeting nonpower constraints is available to BPA in its power marketing program.

Decision: The Corps and Reclamation have carefully reviewed their spending forecasts and believe that further reductions in spending would impair the reliability and efficiency of the system and would not be prudent. Forecasted spending levels for the Corps and Reclamation will be reduced \$2.3 million for FY 2010 and \$7.9 million for FY 2011.

C. LONG-TERM GENERATING PROGRAM

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.

	IPR1		Final IPR2 Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
\$ in thousands						
Power						
Long Term Generation Program	31,889	32,343	30,455	30,767	(1,434)	(1,576)

Proposed Changes: Revised analysis for the WP-10 rate case have resulted in decreases of \$1.4 million in FY 2010 and \$1.6 million in FY 2011.

Comments Received: None

Decision: Revised analysis for the Power rate case resulted in slight adjustments to the forecasted costs of three resources, producing a \$3.0 million reduction in FY 2010-2011.

D. ENERGY EFFICIENCY & CONSERVATION

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 average megawatts per year).

	IPR1		Final IPR2 Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
\$ in thousands						
Power						
Conservation	87,088	86,722	85,588	86,722	(1,500)	-

Proposed Changes:

- Northwest Energy Efficiency Alliance (NEEA) revised business plan calls for increased funding to support its efforts. BPA currently funds about 50 percent of NEEA's \$20 million per year budget which expires September 30, 2009. BPA's share of the total NEEA budget will be reduced to an estimated 37 percent in FY 2010, but overall, NEEA's proposed budget will increase to \$40 million per year. Although BPA has not endorsed the revised business plan, the IPR2 proposal assumes an increase of \$2.5 million per year. This is a \$0.5 million per year decrease from what was included in the April 24 Draft Report.
- Conservation Rate Credit forecast was reduced by \$4 million in FY 2010 and \$2.5 million in FY 2011. This is a correction to reflect the actual CRC. The CRC is a calculation of 0.5 mill times load for both Conservation and Renewable Resources. Since the Renewable Resources credit was increased by \$4 million and \$2.5 million in FY 2010 and FY 2011, the conservation credit should have been reduced by the same amount.

Comments Received:

- NW Energy Coalition is concerned the funding level for energy efficiency will not be enough to meet conservation targets set by Power Councils new 6th plan. BPA needs to be prepared to fund expansion of programs and ramp up infrastructure required to meet cost-effective targets.
- NW Energy Coalition recommends BPA fund energy efficiency at a level at least 30% higher than the \$86 million 2010 budget and 50% higher for 2011, or about \$112 million and \$130 million respectively.
- Springfield Utility Board (SUB) recommends that BPA should not dedicate conservation funding toward projects proposed by Direct Service Industries (DSI's).
- SUB suggests BPA prioritize its efforts and funding to address needs within BPA's high voltage system by making the system "smarter" by installing relays and infrastructure to meet load shedding requirements while benefiting from additional data points and flexibility managing the system.
- The PPC believes the level of BPA's EE program proposed in the April 25, 2009 Draft Decisions Report, is sufficient to achieve the public utilities' share of the NWPCC's target.
- The PPC states that the public utilities agree that BPA's proposed conservation budget is more than sufficient to enable BPA to meet its share of the NWPCC's target. BPA is encouraged to continue working with the PPC to develop programs that accommodate the needs of customers and the circumstances that arise in the post-2011 world.

Decision: At this time, there is considerable uncertainty regarding the new conservation targets that will be published in the Council's Sixth Power Plan. BPA's proposed spending anticipated a substantial increase in BPA's conservation targets (from 56 aMW/year to 70 aMW/year). Although preliminary information indicates that the Council's conservation targets will go even higher, BPA will stand by its proposed Energy Efficiency spending levels at this time. The only changes result from corrections to the Conservation amount which modifies the forecasted spending level by reducing the FY 2010 amount by \$1.5 million.

E. FISH AND WILDLIFE DIRECT PROGRAM

BPA expends ratepayer revenues in the implementation of measures for avoiding jeopardy to, and supporting the recovery of Columbia River fish listed as threatened or endangered under the Endangered Species Act (ESA) and for the protection, mitigation and enhancement of fish and wildlife affected by the development and operation of the Federal Columbia River Power System under the Northwest Power Act. This 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 by the Northwest Power and Conservation Council pursuant to the Northwest Power Act.

BPA meets these complementary fish and wildlife objectives in the Direct Program primarily through the negotiation and award of contracts to state, federal, and tribal entities.

	IPR1		Final IPR2 Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
\$ in thousands						
Power						
Fish & Wildlife	263,583	270,714	248,583	270,714	(15,000)	-

Proposed Changes: In recognition of the fact that some of the new efforts associated with the 2008 Columbia Basin Fish Accords with certain tribes and states are taking longer to ramp up than was anticipated, CRITFC and its member tribes have worked with BPA to establish an updated estimate of the actual spending needs for FY 2009 and FY 2010. This results in an expected reduction of \$15 million in each of those years.

Comments Received:

- Benton Rural Electric suggests BPA recognize it has not been able to spend all of budgeted F&W money.
- The PPC requests that BPA include in the final IPR2 report a showing of the exact amount of fish and wildlife costs in the PF rate, including lost revenues and outline a long-term budget cap that gives ratepayers cost certainty during this challenging time.
- The PPC recommends BPA not commit to an automatic 2.5% inflation rate for the overall F&W program.
- The PPC supports the Independent Economic Analysis Board (IEAB) and request the IEAB be adequately funded so that it can perform this vital function.

Decision: Regarding the request that this document show the amount of fish and wildlife costs in the PF rate, the IPR process is not the appropriate forum in which to provide these estimates, particularly since the operations costs are determined outside this process.

Regarding the recommendation to not commit to a 2.5 percent inflation rate across the program, the proposed FY 2010-2011 funding level for the non- Accord portion of the Fish and Wildlife Program has been held steady (relative to FY 2007-2009, and actually going all the way back to FY 2003) except for a commitment to allow the same 2.5 percent inflation rate that is allowed with the Fish Accord projects. BPA believes it would not be equitable to go back on that commitment at this time.

In response to the suggestion that BPA provide a long-term budget cap that gives rate payers cost certainty, BPA believes that the Accords and new FCRPS Biological Opinion provide 10-year certainty for most components of BPA's fish and wildlife costs, including operational costs. However, there is no certainty or clarity from a legal standpoint about whether the FCRPS Biological Opinion will be acceptable to the Courts. So while we understand the interest in having long-term certainty, we cannot provide that certainty at this time given the ongoing legal proceeding.

Columbia River Inter-Tribal Fish Commission (CRITFC) and its member tribes have worked with BPA to establish an updated estimate of the actual spending for implementation of the Fish Accords in FY 2009 and FY 2010. The updated forecast results in expected Fish and Wildlife Program spending being \$15 million lower in FY 2009 and FY 2010 as compared to anticipated Program spending levels at the conclusion of the IPR1 process.

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

This program funds 11 hatcheries and 15 satellite facilities owned and operated by the U.S. Fish and Wildlife Service (FWS); the fisheries agencies of the states of Oregon, Washington, and Idaho; and the Nez Perce, Shoshone-Bannock, 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 the 1970s.

Comments Received: None

Decision: No Change

G. RENEWABLE RESOURCES

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.

	IPR1		Final IPR2 Decisions		Change	
\$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
Power						
Renewables includes Rate Credit	45,588	45,938	45,588	44,638	-	(1,300)

Proposed Changes: Technology Innovation Research and Development will be reduced by \$2.6 million in FY 2011. \$1.3 million appears as a reduction to Power Renewable Resources.

Comments Received:

- The PPC supports a reduction to the Renewable Resources program in FY 2010 to \$4 million and \$2 million in FY 2011. BPA’s latest Draft Decisions Report shows \$2.5 million in FY 2011. The PPC proposes to remove the extra half million dollars to lower the FY 2011 level back to the \$2 million the publics originally proposed. The PPC recommends that BPA work with its customers to better gauge the current level of potential interest in this product to ensure the money collected through rates is reasonably expected to be used.

Decision: BPA believes the decision made in IPR1 for the Renewable Option to the Conservation Rate Credit for \$2.5 million in FY 2011 is the appropriate level, making \$2 million available to support the Wind Integration Team initiatives and have \$0.5 million available for other opportunities. As described in the Internal Costs section, additional reductions were made to Technology Innovation Research and Development costs, reducing the FY 2011 levels to the FY 2010 levels, in response to the region’s economic conditions. This results in a reduction in this program of \$1.3 million in FY 2011.

H. 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 draft decisions 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.

The capital-related costs in the March 18 IPR2 material is the most current forecast. The final rate proposal will include repayment studies updated for 2nd Quarter forecasts of 2009 capital investment and actual 2009 investment to date.

SECTION 4: TRANSMISSION

A. TRANSMISSION AGENCY SERVICES RE-ALLOCATION AND POST-RETIREMENT CONTRIBUTION

	IPR		Final IPR2 Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
\$ in thousands						
Transmission						
Agency Services Re-Allocation (3/18/09)	58,900	58,900	50,338	50,295	(8,562)	(8,605)
Post-Retirement Contribution	15,598	16,071	15,447	15,579	(151)	(492)
Total	74,498	74,971	65,785	65,874	(8,713)	(9,097)

Proposed Changes:

- Due to a review of Agency Services allocations, \$8.6 million of forecasted spending has been allocated to capital instead of expense in FY 2010 and FY 2011.
- Change in Post-Retirement Contribution forecast of expenses updated to reflect changes in forecasted BFTE levels, slower CSRS employee retirements and a slower rate of growth of health care costs than previously forecasted.

Comments Received: None

Decision: Forecasted spending levels for Agency Services and Post-Retirement Contribution will be reduced by \$8.9 million for FY 2010 and \$9.4 million for FY 2011.

B. TRANSMISSION INTERNAL OPERATION REDUCTIONS TO AGENCY SERVICES & TRANSMISSION

	IPR1		Final IPR2 Decisions		Change	
	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
\$ in thousands						
Transmission						
Internal Operation Reductions (Agency Services & Transmission)	-	-	(5,758)	(7,054)	(5,758)	(7,054)

Proposed Changes:

- An additional reduction to Agency Services and Transmission reflects the impact of IPR2 revised estimates, award reductions and reduced COLA assumptions. The reduction from IPR1 to the Final Decisions shown here is greater than the amounts included in the Draft Final Report. The reductions in the Draft Report reflected *estimates* of changes due to Agency Services costs reductions (including the allocation of those reductions), changes due to removing Success Share and Team Share from both Agency Services and Transmission, and the impact of changes to the split of allocations between transmission expense and capital. The reduction amounts here have been updated to reflect the correct savings and allocation amounts. In addition, Technology Innovation Research and Development was reduced by \$2.6 million, \$1.3 million of which is reflected in Transmission Services.
- As described in Section 3, the final rate proposal will include updated 2009 actuals and forecast.

Comments Received: None

Decision: Forecasted spending levels for Internal Operation Reductions (Agency Services and Transmission) will be reduced by \$5.1 million for FY 2010 and \$6.4 million for FY 2011.

C. ALL OTHER TRANSMISSION COSTS

Comments Received: None

Decision: No Change

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APPENDIX B
REPAYMENT PROGRAM TABLES

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Appendix B is being discontinued because the tables duplicated information contained in the documentation of this study. Two tables have been moved into the body of the Study, one to replace a less detailed table and one to directly support the demonstration of cost recovery over the repayment period. Table 2, Planned Federal Amortization and Irrigation Assistance Payments, contains all of the information previously displayed in Table 10 of this Appendix. The new Table 10, Amortization of Investments Over Repayment Period, contains the information previously found in Table 12A in this Appendix.

Information on the principal and interest payments for Federal investments can be found in Volume 2 of the Documentation. *See* Documentation, WP-10-FS-BPA-02B, Tables 2C, 2D, 4C, and 4D.

The application of amortization by project for the repayment period can be found in Volume 2 of the Documentation. *Id.* at Table 4B.

Information on the principal and interest payment components of capitalized contracts can be found in Volume 1 of the Documentation. *See* Documentation, WP-10-FS-BPA-02A at Chapter 8.

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