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

2010 BPA Rate Case
Wholesale Transmission Rate Final Proposal

REVENUE REQUIREMENT STUDY

July 2009

TR-10-FS-BPA-01

BONNEVILLE
POWER ADMINISTRATION

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TRANSMISSION REVENUE REQUIREMENT STUDY

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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. INTRODUCTION

The purpose of the Revenue Requirement Study (Study) is to establish the level of revenues needed from rates for Bonneville Power Administration's (BPA's) transmission and ancillary services to recover, in accordance with sound business principles, costs associated with the transmission of electric power over the Federal Columbia River Transmission System (FCRTS). The FCRTS is part of the larger Federal Columbia River Power System (FCRPS), which also includes the hydroelectric, multipurpose facilities constructed and operated by the U.S. Army Corps of Engineers (COE) and the U.S. Bureau of Reclamation (Reclamation) in the Pacific Northwest. The FCRPS costs that are not associated with the FCRTS are funded and repaid through BPA power rates. The transmission revenue requirements herein include recovery of the Federal investment in transmission and transmission-related assets; the operations and maintenance (O&M) and other annual expenses associated with the provision of transmission and ancillary services; the cost of generation inputs for ancillary services and other inter-business-line services necessary for the transmission of power; and all other transmission-related costs incurred by the Administrator.

The cost evaluation period for this rate proposal includes Fiscal Years (FYs) 2009-2011, the period extending from the last year for which historical information is available through the proposed rate approval period (rate test period). The Study includes the transmission revenue requirements for the rate test period, FY 2010-2011, which incorporates the results of transmission repayment studies.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine BPA's transmission revenue requirements. Legal requirements are summarized in Chapter 5 of this Study. The Documentation for the Revenue Requirement Study, TR-10-FS-BPA-01A, contains key technical assumptions and calculations, the results of the transmission repayment studies, and a further explanation of the repayment inputs and its outputs.

The revenue requirements that appear in this Study are developed using a cost accounting analysis comprised of multiple steps. *See* Figure 1, Transmission Revenue Requirement Process. The primary features of the Study include repayment studies, transmission operating expenses, and risk analysis. First, repayment studies for the transmission function are prepared to determine an amortization schedule and to project the resulting annual interest expense for bonds and appropriations that fund the Federal investment in transmission and transmission-related assets. Repayment studies are conducted for each year of the rate test period and extend over a 35-year repayment period. Second, transmission operating expenses, non-Federal debt service requirements, and minimum required net revenues (if needed) are projected for each year of the rate test period. Third, the necessity for including annual planned net revenues for risk is evaluated by taking into account Transmission's business risks, BPA's cost recovery goals, and risk mitigation measures. From these three steps, revenue requirements are set at the revenue level necessary to fulfill BPA's cost recovery requirements and objectives.

BPA conducts current and revised revenue tests to determine whether revenues projected from current and proposed rates meet its cost recovery requirements and objectives for the rate test and repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, current rates could be extended. The current revenue test, discussed in section 4.2, demonstrates that current revenues are insufficient to meet cost recovery requirements and objectives for the proposed rate approval period and the repayment period.

The revised revenue test determines whether projected revenues from proposed rates are sufficient to meet cost recovery requirements for the rate test and repayment periods. The revised revenue test, contained in section 4.3, demonstrates that revenues from proposed rates recover the costs of transmission and ancillary and control area services in the rate test period as well as over the ensuing 35-year repayment period.

Consistent with the Treasury Payment Probability (TPP) standard that BPA adopted as a long-term policy in 1993, the revenues from the transmission and ancillary services rates in this final rate proposal provide a greater than 95 percent probability that associated U.S. Treasury payments will be made on time and in full over the two-year rate period. *See* section 2.2.

Table 1 shows projected net revenues from proposed rates and summarizes the revised revenue test over the two-year rate period. In combination with other risk mitigation tools, these net revenues are set at the lowest level necessary to achieve BPA's cost recovery objectives in the face of transmission-related risks. Table 2 shows planned transmission amortization repayments to the U.S. Treasury for each year of the proposed rate approval period.

2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

2.1 Development Process for TR-10 Rate Case Spending Levels

BPA has long worked to ensure that its decision-making process is open and transparent to its customers and constituents. In response to interest expressed by Regional Dialogue participants, BPA developed the Integrated Business Review (IBR) to provide customers and constituents the opportunity to provide meaningful and tangible input into BPA's long-term budget setting process.

2.1.1 Integrated Business Review

The IBR entails two processes, the Integrated Program Review (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 on-going 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.

2.1.2 Integrated Program Review

The IPR was designed to provide customers and constituents an opportunity to examine, understand, and comment on BPA's cost projections for both power and transmission rate proceedings. BPA began the IPR for FY 2010-2011 program levels on May 15, 2008, with a workshop containing an overview of all Power and Transmission services proposed spending levels thru FY 2011. BPA conducted five subsequent workshops on Transmission programs. At the workshops, BPA conducted detailed discussions outlining transmission capital spending levels and planned transmission system improvements, upgrades, and reinforcement projects. Additionally, while asset management plans and debt management issues are not decided in the IPR forum, BPA held workshops on these topics to better inform participants about the implications of past debt management decisions and proposed capital spending levels. Notices of the workshops were distributed widely to TS customers and interested parties and posted on BPA's Web site. At the conclusion of the IPR process, BPA issued a close-out letter and report setting forth the Administrator's decision on spending levels.

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

The public comment period on the proposed TS FY 2010-2011 program spending levels ran from May 15, 2008, to August 15, 2008. Workshop participants provided substantial oral and written comments regarding TS planned transmission capital spending and program expenditures. Based on comments received during the IPR process and on internal reassessment, BPA changed some of its initial forecasts of program spending levels. These changes are reflected in the November 2008 final IPR close-out report. *See* Appendix A. These include reshaping the I-5 corridor project to reflect a more achievable schedule and increasing the lapse factor[1] for transmission capital from 15 percent to 17 percent. This results in an overall reduction of $10 million in FY 2010 and $1.7 million in FY 2011 in transmission capital spending from initial IPR forecasts.

The final close-out letter and report were issued on November 14, 2008. The results of the IPR process were reflected in the rate case Initial Proposal revenue requirements, including repayment studies. BPA also committed to an abbreviated IPR process outside of this rate

[1] The lapse factor is an assumption that a percentage of planned capital investment will be delayed into the subsequent rate period.

proceeding during the spring of 2009 to review and update spending forecasts for FYs 2010 and 2011.

The abbreviated review process, known as IPR 2, began with a kickoff workshop on March 18, 2009. This effort consisted of three workshops on BPA's program spending forecasts, with particular focus on costs that affect power rates. Transmission program expense and capital spending forecasts were not changed in IPR 2. However, reductions in agency cost forecasts are allocated between BPA's business units, resulting in reductions to the Transmission revenue requirement. In addition, a change in allocation between expense and capital was made, further reducing the Transmission expenses. The net change to Transmission program spending forecasts was $30.6 million. The IPR 2 final report is also included in Appendix A of this Study.

After the conclusion of the IPR, the Administrator determined that a portion of the projected spending levels for operations and maintenance programs would be withheld from recovery by transmission rates in the 2010-1011 rate period and would be covered by other sources of funds. As a result of changes in spending levels in IPR 2 and updated repayment study results, $40 million of program spending is being withheld from recovery by rates.

2.2 Financial Risk and Mitigation

BPA adopted a long-term policy in its 1993 Final Rate Proposal that called for setting rates that build and maintain financial reserves sufficient for the agency to achieve a 95 percent Treasury Payment Probability (TPP) of making the end-of-year U.S. Treasury payments in full and on time during the two-year rate period. *See* 1993 Final Rate Proposal, Administrator's Record of Decision, WP-93-A-02, p. 72. Beginning in the 2002 Power and Transmission rate proceedings, this standard was applied separately to both functions. The 95 percent TPP standard was reaffirmed in BPA's Financial Plan published in 2008.[2]

In this rate proceeding, BPA has analyzed its transmission risks and has determined that this rate proposal achieves the 95 percent two-year probability standard for the transmission function for the two-year rate period. To achieve this level of TPP, the following risk mitigation "tools" are considered in the rate proposal.

(1) Starting financial reserves available for risk attributed to Transmission

Starting financial reserves available for risk include cash and the deferred borrowing balance attributed to the transmission function as of the beginning of the rate period. Approximately $157 million of reserves attributed to Transmission at the start of FY 2010 are considered to be encumbered and therefore not available for risk, and are not considered in the risk analysis. These monies include customer deposits for capital projects such as Large Generator Interconnection Agreement (LGIA), Network Open Season, and Southern Intertie capital program deposits, as well as Master Lease funds. They are either deposits from third parties to pay for specific facilities or advances through BPA's Master Lease program that are required by the lease agreement terms to be used only for specified projects. BPA's risk analysis uses a Monte Carlo model to simulate changes in reserves for each year, FY 2009-2011, for each of 3,500 games (iterations). The expected value (mean) from the resultant distribution for the ending FY 2011 reserves is $289.4 million.

(2) Planned Net Revenue for Risk (PNRR)

PNRR is a component of the revenue requirement that is added to annual expenses if reserves are not sufficient for risk mitigation purposes. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short-run volatility in expenses and

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[2] BPA's Financial Plan (2008) and 10-Year Financial Plan (1993) can be found at www.bpa.gov/corporate/Finance/financial_plan/

revenues and achieve the TPP goal. No PNRR is required to meet the TPP standard in this rate proposal.

(3) Two-Year Rate Period

BPA is setting rates for a two-year rate period. The ability to revise rates after two years, or more frequently if need be, serves as an important risk mitigation tool for BPA's transmission function. By using a two-year rate period, BPA limits the amount of risk that must be covered by financial reserves and PNRR.

2.2.1 Transmission Risk Analysis

To quantify the effects of risk on the finances of BPA's transmission function, BPA analyzes the effects of uncertainty in expenses and revenues on transmission cash flows using a Monte Carlo simulation method. *See* Figure 2. The analysis is used to estimate the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when the end-of-year financial reserves for the transmission function, after Treasury payments are made, are sufficient to cover the transmission function's liquidity reserves (formerly termed "working capital") requirement of $20 million. The liquidity reserves threshold in the amount of $20 million is based on the historical monthly net cash flow patterns and monthly cash requirements for the transmission function.

The risk analysis covers the period FYs 2009 through 2011. Using this time frame permits analysis of the change in revenues, expenses, and accrual-to-cash adjustments that are expected to occur between now and the end of the rate period. The advantage to this approach is that financial reserves at the start of the next rate period (FY 2010-2011) may be simulated, including the effects of uncertainty in current rate period (FY 2009) cash flows, thus helping define the starting conditions for the next rate period.

The risk analysis model starts from a known level of financial reserves at the beginning of FY 2009, and simulates risks that can affect the level of reserves throughout FY 2009 and the FY 2010-2011 rate period, and can be used to calculate the required amount of PNRR if reserves are not sufficient to meet BPA's TPP standard. Input values for point estimates of expenses come from the Study, and the revenue inputs are from the revenue forecast. These inputs, when combined with inputs describing uncertainty in expenses and revenues, provide the basis for the estimate of PNRR. The PNRR, in turn, is provided as an input to the Study, raising the transmission revenue requirement and transmission rates if needed to raise TPP. This iterative process is continued until successive estimates of PNRR converge. *See* Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 9.

2.2.2 Transmission Risk Analysis Model

The foundation of the risk analysis is a transmission financial spreadsheet model. *Id*. This model was developed to estimate the effects of risk and risk mitigation tools on end-of-year financial reserves and the likelihood of successful Treasury end-of-year payment for each year during the rate period. Financial reserve levels at the end of each fiscal year determine whether BPA is able to meet its Treasury payment obligation. The model contains individual work sheets, including an input matrix of revenues and expenses, an income statement, a cash flow statement, accrual-to-cash adjustments, and individual work sheets for variables specified with uncertainty in the model. Parameters for the probability distributions were developed from historical data when available. When historical data were not available, or when the future is expected to be different from the past, BPA relied on the judgment of technical staff familiar with specific areas of transmission risk as the basis for forecasting the uncertainty in those risks.

2.3 Capital Funding

BPA transmission capital outlay projections for this proposal are $898.5 million for the FY 2010-2011 rate period. These investments are:

- transmission programs ($864.3 million);
- environmental program ($9.3 million);
- information technology projects ($24.9 million).

2.3.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be the primary source of capital used to finance projected FY 2010-2011 transmission capital program investments. Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in the Documentation for the Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 6.

2.3.2 Federal Appropriations

This Study includes the outstanding balances of the original capital investments in the Federal transmission system that were financed by Congressional appropriations. Transmission investments were no longer funded by appropriations after the full implementation of BPA's self-funding authority under the Federal Columbia River Transmission System Act (Transmission System Act). The Bonneville Appropriations Refinancing Act (Refinancing Act) reset the unpaid principal of all outstanding BPA appropriations and reassigned current market interest rates. New principal amounts were established at the beginning of FY 1997 at the present value of the principal and annual interest payments BPA would make to the Treasury for these obligations in the absence of the Refinancing Act, plus $100 million. Before implementation of the Refinancing Act, there was $1,461.9 million in BPA appropriations outstanding. After the implementation of the Refinancing Act, $1,075.4 million in BPA appropriations was outstanding. The Refinancing Act restricted prepayment of the new principal to $100 million in the FY 1997-2001 period. Other repayment terms were unaffected. Through annual repayments, Transmission outstanding appropriations had been reduced to $489 million as of September 30, 2008.

2.3.3 Use of Cash Reserves

As a means to fund capital investments, BPA will rely on $15 million per year from Transmission cash reserves during this Rate Period. This amount will be drawn from reserves projected to be available in the Rate Period.

2.3.4 Non-Federal Payment Obligations

The transmission revenue requirements reflect two forms of non-Federal payment obligations. The first form consists of lease financing arrangements for asset purchases. BPA entered into a transaction in 2004 with the Northwest Infrastructure Financing Corporation (NIFC), a subsidiary of JH Management, to provide for the construction of the 500 kV Schultz-Wautoma transmission line (Shultz-Wautoma line). BPA will make semi-annual lease payments for 30 years, concluding with a single payment for the principal due on the bonds issued by NFIC. Payment of the debt incurred by NIFC to construct the line is secured solely by BPA's revenues. During the term of the lease, TS will operate the Schultz-Wautoma line and provide transmission and ancillary services over the facilities. Since the completion of the Schulz-Wautoma project, BPA has entered into additional lease financing arrangements with NIFC and will continue to do so. The revenue requirement includes all transactions completed up to the date of the Final proposal. It does not include forecasts of additional transactions.

The second form of non-Federal payment obligations included in the revenue requirements consists of the functional reassignment to TS of debt service (interest and principal) payment obligations associated with non-Federal Energy Northwest (EN) bonds. This reassignment is a result of BPA's Debt Optimization Program, which refinances and repays existing EN bonds before they come due and uses the revenues made available from such refinancing to replenish or create opportunities to replenish BPA's Treasury borrowing authority by retiring additional Treasury obligations in amounts equal to the amount of principal of the new EN bonds**.** When Treasury obligations associated with transmission investments are repaid under the Debt Optimization Program, the debt service obligation associated with new EN debt in equivalent principal amounts is assigned to the TS. The revenue requirements reflect refinancing actions that have occurred through FY 2008. The revenue requirement does not include forecasts of additional refinancing activities during the cost evaluation period.

For specific calculations regarding non-Federal payment obligations, *see* Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 7.

2.3.5 Large Generator Interconnection Agreements

BPA amended its Open Access Transmission Tariff by adopting the LGIA in voluntary compliance with FERC Orders 2003 and 2003A. Under the LGIA, interconnection customers finance the cost of Network Upgrades needed to interconnect their generating facilities to BPA's transmission system, if BPA, as the transmission owner/provider, does not provide the funding. BPA requires the interconnection customer to advance funds in an amount sufficient to cover the cost of construction. These advance funds, which earn interest on the outstanding balance, are then returned to the interconnection customer in the form of transmission credits. The credits are used to offset charges for eligible transmission service in a customer's bill. This Study includes a forecast of the transmission and interest expense and credited revenues associated with each LGIA project.

3. DEVELOPMENT OF REPAYMENT STUDIES

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

In this Study, as in the previous transmission rate filing, the repayment period has been set at 35 years. This study horizon reflects the fact that bonds are not issued for terms longer than 35 years and that the outstanding appropriations and bonds in the transmission system are fully repaid within this period. It also is consistent with the estimated average service life of transmission system plant (40 years) by not exceeding that average lifetime. The Revenue Requirement Study includes the results of transmission repayment studies for each year in the rate test period, FYs 2010 and 2011. In conducting the repayment studies, BPA includes outstanding and projected transmission repayment obligations for Congressional appropriations and bonds issued to the U.S. Treasury. Funding for replacements projected during the repayment period also is included in the repayment study, consistent with the requirements of RA 6120.2. *See* section 5.2 of this study.

Historical BPA appropriations are scheduled to be repaid within the expected useful life of the associated facility or 50 years, whichever is less. Actual bonds issued by BPA to the Treasury may be for terms ranging from 3 to 40 years, taking into account the estimated average service lives for associated investments and prudent financing and cash management factors. In the repayment studies, all projected bonds have a term of 35 years for transmission investment and 15 years for environment investment. Some bonds are issued with a provision that allows the bond to be called after a certain time, typically five years. Bonds also may be issued with no early call provision. Early retirement of eligible bonds requires that BPA pay a bond premium to the Treasury. The premium that must be paid decreases with the age of the bond, and is equivalent, in total, to a fixed premium and a reduced interest rate. This reduced effective interest rate enters into the comparison with other Federal investments and obligations to determine which should be repaid first. Bonds are issued to finance BPA transmission and environment investments and are repaid within the provisions of each bond agreement with the Treasury.

The streams of annual debt service pertaining to non-Federal payment obligations also are included as fixed obligations that the repayment study takes into account in establishing the overall levelized debt service. This reflects the priority of revenue application in legislation and DOE Order RA 6120.2, in which these obligations have a higher priority of debt repayment. Therefore, the study scheduled the repayment of Federal debt around these obligations.

Based on these parameters, the repayment study establishes a schedule of planned Federal amortization payments and resulting gross Federal interest expense by determining the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period. Further discussion of the repayment program is included in the Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 12. Section 5.2 of this Study explains repayment policies and requirements.

4. TRANSMISSION REVENUE REQUIREMENTS

This chapter explains the cost accounting formats used to develop the revenue requirements for FYs 2010 and 2011. Section 4.1.1 provides a line-by-line description of the Revenue Requirement Income Statement, and section 4.1.2 provides a line-by-line description of the Revenue Requirement Statement of Cash Flows.

4.1 Revenue Requirement Format

For each year of a rate period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, Planned Net Revenues for Risk, and, if necessary, a Minimum Required Net Revenues component. The Statement of Cash Flows shows the analysis used to determine Minimum Required Net Revenues and the cash available for risk mitigation.

The Income Statement (Table 3 of this Study) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 9), Net Interest Expense (Line 20), Minimum Required Net Revenues (Line 22), and Planned Net Revenues for Risk (Line 23). The sum of these four major components is the Total Revenue Requirement (Line 25) for each year of the rate period.

The Minimum Required Net Revenues (Table 3, Line 22) result from an analysis of the Statement of Cash Flows (Table 4 of this Study). Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the transmission repayment studies.

The Statement of Cash Flows (Table 4) analyzes annual cash inflows and outflows. Cash Provided by Current Operations (Line 10), driven by the Expenses Not Requiring Cash shown in Lines 4, 5, and 6, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 14) and Cash from Treasury Borrowing (Line 20). If cash provided by Current Operations is not sufficient, Minimum Required Net Revenues (Line 2) must be included in revenue requirements to accommodate the shortfall, yielding at least a zero Annual Increase in Cash (Line 21). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) then is incorporated in the Income Statement (Table 3, Line 21).

4.1.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 3). The Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 2, provides additional information on the development and use of the data contained in the tables.

Transmission Operations (Line 2). Transmission Operations includes spending for technical operations, substation operations, control center support, power system dispatching, and Transmission information technology (IT) costs, including Agency Services IT costs that are allocated to Transmission Services, and scheduling services (reservations, pre-scheduling, real-time and after-the-fact scheduling, and technical support). This category also includes spending for business strategy and assessment, billing, finance, contract management, and internal operations. *See* Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 2.

Transmission Maintenance (Line 3). This category includes spending for all Transmission Services maintenance activities such as on-going maintenance of substations, lines, and protection control systems. This category also includes spending on environmental analysis and pollution prevention and abatement. *Id.*

Transmission Engineering (Line 4). This category includes spending on asset management and planning, design of lines/towers/substations, construction planning, construction management, and real property services. *Id*.

Transmission Acquisition & Ancillary Services (Line 5). Inter-business line expenses, resulting from functional separation, and ancillary services products, include the Power Services generation inputs to ancillary services, station service and remedial action schemes, and the cost of Corps and Reclamation transmission facilities serving the network and utility delivery segments. *Id*. Also included are payments to other utilities for stability reserves, settlements, and operating leases. *Id*.

BPA Internal Support (Line 6). This category includes spending on general and administrative programs that are allocated to BPA's two business units. These programs include legal services, finance, risk management, security and emergency management, human resources, and executive oversight and management. *Id*.

Other Income, Expenses & Adjustments (Line 7). For the purposes of the rate case settlement and for convenience, this category includes the adjustment for expenses excluded from rates that was described in Chapter 2.

Depreciation & Amortization (Line 8). Depreciation is the annual capital recovery expense associated with FCRTS plant-in-service. BPA transmission and general plant are depreciated by the straight-line method of calculation, using the remaining life technique. Amortization refers to the annual capital recovery expense for other deferred Transmission assets. *Id*.

Total Operating Expenses (Line 9). Total Operating Expenses is the sum of the above expenses (Lines 2 through 8).

Federal Appropriations (Line 12). Federal Appropriations consists of interest on the appropriations BPA received prior to full implementation of BPA's self-financing authority and is determined in the transmission repayment studies. *Id*.

Capitalization Adjustment (Line 13). Implementation of the Refinancing Act entailed a change in capitalization on BPA's financial statements. Outstanding appropriations attributed to the transmission function were reduced by $470 million as a result of the refinancing. The reduction is recognized annually over the remaining repayment period of the refinanced appropriations. The annual recognition of this adjustment is based on the increase in annual interest expense resulting from implementation of the Act, as shown in repayment studies for the year of the refinancing transaction (1997). The capitalization adjustment is included on the income statement as a non-cash, contra-expense. *Id*.

Long-Term Debt (Line 14). Long-term debt includes interest on bonds that BPA issues to the Treasury to fund investments in transmission plant, environment, general plant supportive of transmission, and capital equipment. Such interest expense is determined in the transmission repayment studies. Any payments of call premiums for bonds projected to be amortized are included in this line. *Id*.

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

Debt Service Reassignment Interest (Line 16). Debt service reassignment interest consists of the interest component of the debt service reassigned to TS through the Debt Optimization Program. *Id.* at Chapter 7.

Non-Federal Interest (Line 17). Non-Federal interest consists of interest paid on BPA's lease financing projects and interest on customer prepayments for Large Generator Interconnection Agreements. The LGIA payments accrue interest on the outstanding balances until they are returned to customers through credits for transmission service.

Allowance for Funds Used During Construction (AFUDC) (Line 18). AFUDC for Treasury-financed transmission projects is a credit against interest on long-term debt (Line 14). This non-cash reduction to interest expense reflects an estimate of interest on the funds used during the construction period of facilities that are not yet in service. Also included is the interest accrued on LGIA funds during the construction period of the associated facilities. AFUDC is capitalized along with other construction costs and is recovered through rates over the expected service life of the related plant as part of the depreciation expense after the facilities are placed in service.

Interest Income (Line 19). Interest income is computed on the projected year-end cash balances in the BPA fund attributable to the transmission function that carries over into the next year. It is credited against bond interest. Also included is an interest income credit calculated in the transmission repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year. A further explanation of the calculation of the interest credit computed within the transmission repayment studies is included in Appendix A. *Id.* at Chapter 4.

Net Interest Expense (Line 20). Net Interest Expense is computed as the sum of the interest on Federal Appropriations (Line 12), Capitalization Adjustment (Line 13), Long Term Debt (Line 14), Amortization of Capitalized Bond Premiums (Line 15), Debt Service Reassignment Interest (Line 16), Non-Federal Interest (Line 17), AFUDC (Line 18), and Interest Income (Line 19).

Total Expenses (Line 21). Total Expenses are the sum of Total Operating Expenses (Line 9) and Net Interest Expense (Line 20).

Minimum Required Net Revenues (Line 22). Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 4), may be necessary to cover cash requirements in excess of accrued expenses. An explanation of the method used for determining the Minimum Required Net Revenues is included in section 4.1.2.

Planned Net Revenues for Risk (Line 23). Planned Net Revenues for Risk is the amount of net revenues, if any, to be included in rates for financial risk mitigation. There are no Planned Net Revenues for Risk included in the Final Rate Proposal. Starting TS reserves in FY 2010 are projected to be sufficient to mitigate risk in FYs 2010 and 2011.

Total Planned Net Revenues (Line 24). Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 22) and Planned Net Revenues for Risk (Line 23).

Total Revenue Requirement (Line 25). Total Revenue Requirement is the sum of Total Expenses (Line 21) and Total Planned Net Revenues (Line 24).

4.1.2 Statement of Cash Flows

Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 4). The Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, provides additional information related to the use and development of the data contained in the cash flow table.

Minimum Required Net Revenues (Line 2). Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required Net Revenues may be necessary so that the Cash Provided By Current Operations (Line 10) will be sufficient to cover the planned amortization payments (the difference between Lines 14 and 20) without causing the Annual Increase (Decrease) in Cash (Line 21) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Table 3, Line 21).

Depreciation & Amortization (Line 4). Depreciation is from the Income Statement (Table 3, Line 8). It is a negative item included in computing Cash Provided By Current Operations (Table 4, Line 10), because it is a non-cash expense of the FCRTS.

Transmission Credit Projects Debt Service (Line 5). Transmission Credit Projects Debt Service is the non-cash expenses from the Income Statement for the LGIA customers' interest on their payment balances (included in Table 3, line 17) and the AFUDC on the projects under construction funded by those payments (included in Table 3, line 18) .

Amortization of Capitalized Bond Premiums (Line 6). Amortization of Capitalized Bond Premiums, from the Income Statement (Table 3, Line 16), is a non-cash expense.

Capitalization Adjustment (Line 7). The Capitalization Adjustment, from the Income Statement (Table 3, Line 17), is a non-cash (contra) expense.

Drawdown of Cash Reserves for Capital Funding (Line 8). The Drawdown of Cash Reserves for Capital Funding refers to the use of cash accumulated from transmission revenues in prior rate periods to fund capital expenditures in each year of the rate period.

Accrual Revenues (AC Intertie/Fiber/LGIA) (Line 9). BPA accounts for the AC Intertie non-Federal capacity ownership lump-sum payments received in FY 1995 as unearned revenues that are recognized as annual accrued revenues over the estimated average service life of the associated transmission facilities. Similarly, some leases of fiber optic capacity have included up-front payments, the annual accrued revenues for which are being recognized over the life of the particular contract. The annual accrual revenues, which are part of the total revenues recovering the FCRTS revenue requirement, are included here as a non-cash adjustment to cash from current operations. In addition, revenue credits associated with LGIA capital projects are included in this category. LGIA customers provide an upfront payment for construction of transmission facilities that is returned to them through the credits for transmission service that result in transmission revenues that do not produce cash.

Cash Provided By Current Operations (Line 10). Cash Provided By Current Operations, the sum of Lines 2, 4, 5, 6, 7, 8, and 9, is available for the year to satisfy cash requirements.

Investment in Utility Plant (Line 13). Investment in Utility Plant represents the annual increase in capital expenditures for additions and replacements to the transmission system funded by Treasury bonds or available cash reserves. *See* Study, TR-10-FS-BPA-01, Chapter 2.

Cash Used for Capital Investments (Line 14). Cash Used for Capital Investments is the sum of investments in utility plant.

Increase in Long-Term Debt (Line 16). Increase in Long-Term Debt reflects the new bonds issued by BPA to the U.S. Treasury to fund the construction and environmental capital equipment programs. Also included in this amount may be any notes issued to the U.S. Treasury. *See* Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 6.

Debt Service Reassignment Principal (Line 17). Debt Service Reassignment Principal is the principal component of the debt service obligation reassigned to TS through the Debt Optimization Program. *See* Study, TR-10-FS-BPA-01, section 2.3.4.

Repayment of Long-Term Debt (Line 18). Repayment of Long-Term Debt is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury, as determined in the repayment studies. *See* Documentation for Revenue Requirement Study, TR-10-FS-BPA-01A, Chapter 2.

Repayment of Capital Appropriations (Line 19). Repayment of Capital Appropriations represents projected amortization of outstanding BPA appropriations (pre-self-financing) as determined in the repayment studies. *Id*.

Cash From Treasury Borrowing and Appropriations (Line 20). Cash From Treasury Borrowing and Appropriations is the sum of Lines 16 through 19. This is the net cash flow resulting from increases in cash from new long-term debt and decreases in cash from repayment of long-term debt and capital appropriations.

Annual Increase (Decrease) in Cash (Line 21). Annual Increase (Decrease) in Cash, the sum of Lines 10, 14, and 20, reflects the annual net cash flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues are insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease. *See* above discussion of Minimum Required Net Revenues (Line 2).

Planned Net Revenues For Risk (Line 22). Planned Net Revenues For Risk reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 3, Line 22.)

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

4.2 Current Revenue Test

Consistent with RA 6120.2, the adequacy of existing rates must be tested annually. The current revenue test determines whether the revenues expected from current rates will continue to meet cost recovery requirements.

For the rate test period, the demonstration of the adequacy of current rates is shown on Tables 5 and 6. Table 5 is a pro forma income statement for each year. Table 6, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 5 (Line 23) for making the planned annual amortization payments. The Total Annual Increase (Decrease) in Cash (Table 6, Line 21) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements. The current revenue test shows that current rates are not sufficient to satisfy cost recovery requirements in the rate period because of increased costs associated with certain ancillary and control services.

4.3 Revised Revenue Test

Table 7 shows the adequacy of current rates to satisfy cost recovery requirements over the 35-year repayment period. The focal point of this table is the Net Position (Column K), which is the amount of funds provided by revenues from current rates that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues from current rates demonstrate BPA's ability to repay the Federal investment in the FCRTS within the allowable time. As shown in Column K, the Net Position results are positive for each year of the rate approval period and in each year of the repayment period.

4.4 Revised Revenue Test

Consistent with RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements and the Treasury Payment Probability risk goal for the rate approval period. The revised revenue test was conducted using the forecast of revenues under proposed rates. *See* Documentation, TR-10-FS-BPA-01A, Chapter 14, for the revenue forecasts under current and proposed rates. As part of the partial settlement agreement, BPA extended rates for transmission and certain ancillary services. BPA revised the remaining ancillary and control area services rates to ensure cost recovery. The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery requirements for the rate test period, FY 2010-2011.

For the rate test period, the demonstration of the adequacy of proposed rates is shown on Tables 8 and 9. Table 8 presents pro forma income statements for each year. Table 9, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 8 (Line 23) for making the planned annual amortization. This is demonstrated by the Total Annual Increase (Decrease) in Cash (Table 9, Line 21). The annual cash flow (Line 21) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements.

4.5 Repayment Test at Proposed Rates

Table 10 demonstrates whether projected revenues from proposed rates are adequate to meet the cost recovery criteria of RA 6120.2 over the repayment period. The data are presented in a format consistent with the revised revenue tests (Tables 8 and 9) and separate accounting analyses. The focal point of this table is the Net Position (Table 10, Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRTS within the allowable time. As shown in Column K, the resulting Net Position is greater than zero for each year of the rate approval period and in each year of the repayment period.

The historical data on this table have been taken from BPA's separate accounting analysis. The rate test period data have been developed specifically for this rate filing. The repayment period data are presented in a manner consistent with the requirements of RA 6120.2

Table 11 summarizes the amortization of Federal investments over the entire repayment period. It displays the total investment costs of the transmission projects through the cost evaluation period, forecasted replacements required to maintain the system through the repayment period, the cumulative dollar amount of the generation investment placed in service, scheduled amortization payments for each year of the repayment period (due and discretionary), unamortized investments including replacements through the repayment period, and unamortized obligations as determined by a term schedule (if all obligations were paid at maturity and never early).

5. LEGAL REQUIREMENTS AND POLICIES

This chapter summarizes the statutory framework that guides the development of BPA's transmission revenue requirement and the recovery of BPA's transmission costs among the various users of the FCRTS, and the repayment policies that BPA follows in the development of its revenue requirement.

5.1 Development of BPA's Revenue Requirements

BPA's revenue requirements are governed by three main legislative acts: 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; and the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, 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. In addition, policies issued by the FERC provide guidance on transmission pricing. *See, e.g.*, Bonneville Power Administration, 25 ¶ 61,140 (1983).

5.1.1 Legal Requirement Governing BPA's Revenue Requirement.

BPA constructs, operates, and maintains the FCRTS within the Pacific Northwest and makes improvements or replacements thereto as are appropriate and required to: (a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units;

(b) provide service to BPA customers; (c) provide inter-regional transmission facilities; and (d) maintain the electrical stability and reliability of the Federal system. Section 4, Transmission System Act, 16 U.S.C. § 838b. The transmission system is built to encourage the widest possible use of all electric energy. Section 5, Flood Control Act, 16 U.S.C. § 825s.

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

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

This cost recovery principle was repeated for Army reservoir projects in Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s (as amended 1977). In 1974, Section 9 of the Transmission System Act, 16 U.S.C, § 838g, expanded the cost recovery principle so that BPA's rates also would be set to recover:

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

The Northwest Power Act reiterates and clarifies the cost recovery principle. Section 7(a)(1) of the Northwest Power Act, 16 U.S.C. § 839e(a)(1), provides that:

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

The Northwest Power Act also provides that FERC's confirmation and approval of BPA rates shall ensure that the revenue requirement is adequate to recover BPA's costs and ensure timely U.S. Treasury repayments. Section 7(a)(2), 16 U.S.C. § 839e(a)(2), provides:

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

In October 1992, Congress amended the Federal Power Act to allow FERC to order a transmitting utility, including BPA, to provide transmission services (including the enlargement of transmission capacity necessary to provide such services) to an applicant. Section 211(a), Federal Power Act, 16 U.S.C. § 824j(a). In applying the Federal Power Act provisions to FERC-ordered transmission service on the FCRTS, section 212(i), 16 U.S.C. § 824k(i)(1)(B), provides that FERC shall assure that:

> (i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and
>
> (ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 824i of this title, 824j of this title, this section, and section 824l of this title, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential , as determined by the Commission

In *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 190-92 (2007) (Order 890), FERC decided to retain the safe harbor protections for non-public utilities like BPA from FERC-ordered transmission service under the Federal Power Act that it had established in *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,048 (1997) (Order 888). *See* 18 CFR § 35.28(e). The safe harbor provisions apply if FERC finds the non-public utility's open access transmission tariff is an acceptable reciprocity tariff. In determining whether the non-public utility's tariff is consistent with FERC's comparability standards, FERC requires sufficient information to conclude that the non-public utility's rates associated with tariff service are comparable to the rates it charges others, and also requires that separate rates be established for transmission and ancillary services. Order 888 at ¶ 31,761.

Development of the revenue requirement is a critical component of meeting the statutory cost recovery principles. The costs associated with FCRTS and associated services and expenses, as well as other costs incurred by the Administrator in furtherance of BPA's mission, are included in the Study.

5.1.2 The BPA Appropriations Refinancing Act

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

The Refinancing Act restricts prepayment of the new principal for old capital investments to $100 million during the first five years after the effective date of the financing. 16 U.S.C. § 838l(e). The Refinancing Act also specifies that repayment periods on new principal amounts may not be earlier than determined prior to the refinancing. 16 U.S.C. §838l(d). The Refinancing Act further directs the Administrator to offer to provide assurance in new or existing power, transmission, or related service contracts that the Government would not increase the repayment obligations in the future. 16 U.S.C. §838l(i).

5.2 Repayment Requirements and Policies

5.2.1 Separate Repayment Studies

Section 10 of the Transmission System Act, 16 U.S.C. §838h, and section 7(a)(2)(C) of the Northwest Power Act, 16 U.S.C. §839e(a)(2)(C), provide that the recovery of the costs of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system. In 1982, FERC first directed BPA to provide accounting and repayment statements for its transmission system separate and apart from the accounting and repayment statements for the Federal generation system. *See* 20 FERC ¶61,142 (1982). FERC required BPA to establish books of account for the FCRTS separate from its generation costs; explained that the FCRTS shall be comprised of all investments, including administrative and management costs, related to the transmission of electric power; and directed BPA to develop repayment studies for its transmission function separate from its generation function that set forth the date of each investment, the repayment date, and the amount repaid from transmission revenues. *See* 26 FERC ¶ 61,096 (1984). FERC approved BPA's methodology for separate repayment studies in 1984. 28 FERC ¶ 61,325 (1984).

BPA has prepared separate repayment studies for its transmission and generation functions since 1984. BPA therefore has developed the transmission revenue requirement with no change in this repayment policy.

5.2.2 Repayment Schedules

The statutes applicable to BPA do not include specific directives for scheduling repayment of old capital appropriations and bonds issued to Treasury other than a directive that the Federal investment be amortized over a reasonable period of years. BPA's repayment policy has been established largely through administrative interpretation of its statutory requirements, with congressional encouragement and occasional admonishment.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(5) Repay:

- each dollar of power investments and obligations in the FCRPS generating projects within 50 years after the projects become revenue-producing (50 years has been deemed a "reasonable period" as intended by Congress, except for the Yakima-Chandler Project, which has a legislated amortization period of 66 years);
- each annual increment of transmission financed by Federal investments and obligations within the average service life of such transmission facilities (currently 40 years) or within a maximum of 50 years, whichever is less [BPA has interpreted RA 6120.2 to require repayment of bonds sold to finance conservation

to be within the average service lives of these projects, currently estimated to be five years, and for fish and wildlife facilities to be 15 years];

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

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

While RA 6120.2 allows repayment period of up to 50 years, BPA has set due dates at no more than 40 years to reflect expected service lives of new transmission investment. The Refinancing Act overrides provisions in RA 6120.2 related to determining interest during construction and assigning interest rates to Federal investments financed by appropriations. This Act also contains provisions on repayment periods (due dates) for the refinanced appropriations investments. The Refinancing Act is discussed in section 5.1.2 of this Study.

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

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TABLES

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Table 1: Projected Net Revenues From Proposed Rates

($000s)

	A	B	C	D
1		FY 2010	FY 2011	Rate Period Average
2	Projected Revenues From Proposed Rates	$851,739	$880,361	$866,050
3	Projected Expenses	$772,681	$799,498	$786,089
4	Net Revenues	$79,058	$80,863	$79,961

Table 2: Planned Repayments to U.S. Treasury

($000s)

	A	B	C	D
1	**Bonds**	Due	Scheduled But Not Due	Total
2	2010	140,251	-	140,251
3	2011	100,000	-	100,000
4	Subtotal	240,251	-	240,251
5	**Appropriations**			
6	2010	3,784	71,121	74,905
7	2011	21,232	103,475	124,707
8	Subtotal	25,016	174,595	199,611
9	**Total**	**265,267**	**174,595**	**439,862**

Table 3: Transmission Revenue Requirement Income Statement

($000s)

		A FY 2010	B FY 2011
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	117,472	119,695
3	TRANSMISSION MAINTENANCE	127,306	132,346
4	TRANSMISSION ENGINEERING	23,540	23,675
5	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	103,328	116,422
6	BPA INTERNAL SUPPORT	65,312	65,716
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	(8,000)	(32,000)
8	DEPRECIATION & AMORTIZATION	189,702	201,536
9	TOTAL OPERATING EXPENSES	618,661	627,390
10	INTEREST EXPENSE AND AFUDC		
11	INTEREST EXPENSE		
12	FEDERAL APPROPRIATIONS	32,979	27,538
13	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
14	LONG-TERM DEBT	90,812	112,508
15	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
16	DEBT SERVICE REASSIGNMENT INTEREST	56,781	56,780
17	NON-FEDERAL INTEREST	32,814	40,878
18	AFUDC	(16,501)	(22,648)
19	INTEREST INCOME	(24,479)	(23,201)
20	NET INTEREST EXPENSE	154,196	173,579
21	TOTAL EXPENSES	772,857	800,970
22	MINIMUM REQUIRED NET REVENUES 1/	74,517	75,641
23	PLANNED NET REVENUES FOR RISK	0	0
24	TOTAL PLANNED NET REVENUES	74,517	75,641
25	**TOTAL REVENUE REQUIREMENT**	**847,374**	**876,610**

1/ SEE NOTE ON CASH FLOW TABLE.

Table 4: Transmission Revenue Requirement Statement of Cash Flows

($000s)

		A FY 2010	B FY 2011
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUES 1/	74,517	75,641
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	189,702	201,536
5	TRANSMISSION CREDIT PROJECTS DEBT SERVICE	10,696	13,057
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
9	ACCRUAL REVENUES (AC INTERTIE/FIBER/LGIA)	(41,537)	(47,097)
10	CASH PROVIDED BY CURRENT OPERATIONS	230,168	239,861
11	CASH USED FOR CAPITAL INVESTMENTS:		
12	INVESTMENT IN:		
13	UTILITY PLANT	(443,957)	(454,575)
14	CASH USED FOR CAPITAL INVESTMENTS	(443,957)	(454,575)
15	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
16	INCREASE IN LONG-TERM DEBT	428,957	439,575
17	DEBT SERVICE REASSIGNMENT PRINCIPAL	(12)	(154)
18	REPAYMENT OF LONG-TERM DEBT	(140,251)	(100,000)
19	REPAYMENT OF CAPITAL APPROPRIATIONS	(74,905)	(124,707)
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	213,790	214,714
21	ANNUAL INCREASE (DECREASE) IN CASH	0	0
22	PLANNED NET REVENUES FOR RISK	0	0
23	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0

1/ Line 21 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 5: Current Revenue Test Income Statement

($000s)

		A FY 2010	B FY 2011
1	REVENUES FROM CURRENT RATES	843,365	863,825
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	117,472	119,695
4	TRANSMISSION MAINTENANCE	127,306	132,346
5	TRANSMISSION ENGINEERING	23,540	23,675
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	103,328	116,422
7	BPA INTERNAL SUPPORT	65,312	65,716
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(8,000)	(32,000)
9	DEPRECIATION & AMORTIZATION	189,702	201,536
10	TOTAL OPERATING EXPENSES	618,661	627,390
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	32,979	27,538
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	90,812	112,508
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
17	DEBT SERVICE REASSIGNMENT INTEREST	56,781	56,780
18	NON-FEDERAL INTEREST	32,814	40,878
19	AFUDC	(16,501)	(22,648)
20	INTEREST INCOME	(24,458)	(23,882)
21	NET INTEREST EXPENSE	154,217	172,898
22	TOTAL EXPENSES	772,878	800,289
23	NET REVENUES	70,487	63,536

Table 6: Current Revenue Test Statement of Cash Flows

($000s)

		A FY 2010	B FY 2011
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	70,487	63,536
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	189,702	201,536
5	NON-FEDERAL PROJECTS DEBT SERVICE	10,696	13,057
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
9	ACCRUAL REVENUES (AC INTERTIE/FIBER/LGIA)	(41,537)	(47,097)
10	CASH PROVIDED BY CURRENT OPERATIONS	226,139	227,756
11	CASH USED FOR CAPITAL INVESTMENTS:		
12	INVESTMENT IN:		
13	UTILITY PLANT	(443,957)	(454,575)
14	CASH USED FOR CAPITAL INVESTMENTS	(443,957)	(454,575)
15	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
16	INCREASE IN LONG-TERM DEBT	428,957	439,575
17	DEBT SERVICE REASSIGNMENT PRINCIPAL	(12)	(154)
18	REPAYMENT OF LONG-TERM DEBT	(140,251)	(100,000)
19	REPAYMENT OF CAPITAL APPROPRIATIONS	(74,905)	(124,707)
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	213,790	214,714
21	**ANNUAL INCREASE (DECREASE) IN CASH**	**(4,029)**	**(12,104)**

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

($000s)

	A	B	C	D	E	F	G	H	I	J	K
YEAR COMBINED CUMULATIVE	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	AC INTERTIE CAPACITY OWNERSHIP CAPITAL PAYMENTS (REV REQ STUDY DOC,Chapter 8)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	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
TRANSMISSION											
1978	116,430	69,767		51,503	60,337	(65,177)	51,503	(13,674)	194		(13,868)
1979	107,017	73,801		53,756	69,112	(89,652)	53,756	(35,896)	26		(35,922)
1980	170,603	77,594		55,613	78,039	(40,643)	55,613	14,970	2		14,968
1981	202,740	87,243		59,638	87,665	(31,806)	59,638	27,832	1,236 **2/**		26,596
1982	269,200	91,562		64,458	106,190	6,990	64,458	71,448	0		71,448
1983	359,641	99,520		67,969	138,268	53,884	67,969	121,853	0		121,853
1984	417,821	101,406		60,360	158,783	97,272	60,360	157,632	26,722 **3/**		130,910
1985	510,030	141,623		71,012	160,336	137,059	71,012	208,071	199,646		8,425
1986	446,435	144,438		77,574	178,460	45,963	77,574	123,537	180,915		(57,378)
1987	456,728	148,596		85,807	177,020	45,305	85,807	131,112	148,860		(17,748)
1988	405,154	167,102		90,076	164,131	(16,155)	90,076	73,921	44,757		29,164
1989	422,202	175,240		93,076	164,044	(10,158)	93,076	82,918	119,322		(36,404)
1990	426,855	183,512		98,881	153,440	(8,978)	98,881	89,903	99,460		(9,557)
1991	439,871	199,668		98,731	139,458	2,014	98,731	100,745	70,930		29,815
1992	428,769	209,868		101,946	143,789	(26,834)	101,946	75,112	190,864		(115,752)
1993	417,555	189,926		101,929	173,271	(47,571)	101,929	54,358	130,989		(76,631)
1994	462,511	202,309		103,956	179,052	(22,806)	103,956	81,150	55,977		25,173
1995	490,264	200,501		112,940	181,744	(4,921)	112,940	264,019 **/4**	281,789		(17,770)
1996	534,456	206,128		125,961	165,175	37,192	123,219	145,411 **/5**	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	109,802	114,383	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	117,884	129,855	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	133,779	133,753	139,784		(6,031)
2000	578,340	270,153		154,069	165,330	(11,212)	135,358	124,146	114,587		9,559
2001	646,673	282,851		154,881	165,404	43,537	151,746	195,283	59,064		136,219
2002	720,382	364,511		161,042	150,718	44,111	148,912	193,023	131,667		61,356
2003	663,601	326,248		171,129	168,996	(2,772)	160,628	473,056	470,747		2,309
2004	644,059	313,994		204,445	137,822	(12,202)	225,406	403,481 **/5**	359,500		43,981
2005	634,530	333,584		189,501	135,754	(24,309)	169,180	320,071 **/5**	345,201		(25,130)
2006	784,339	378,872		171,359	136,761	97,347	145,949	432,634 **/5**	384,947		47,687
2007	808,624	372,556		175,584	133,806	126,678	146,762	460,240 **/5**	372,100	716	87,424
2008	844,215	382,879		174,599	136,360	150,377	139,327	384,756 **/5**	277,833	4,510	102,413
COST EVALUATION PERIOD											
2009	830,968	412,684		179,440	126,212	112,632	132,479	280,111 **/5**	222,659	10,407	47,045
RATE APPROVAL PERIOD											
2010	843,365	428,959		189,702	154,217	70,487	140,652	211,139	215,156	12	(4,029)
2011	863,825	425,856		201,536	172,898	63,535	149,222	212,757	224,707	154	(12,104)
REPAYMENT PERIOD											
2012	863,825	425,856	(1,616)	201,536	182,849	55,200	149,220	204,420	175,106	41,118	(11,804)
2013	863,825	425,856	(1,682)	201,536	185,089	53,026	149,220	202,246	47,854	165,628	(11,236)
2014	863,825	425,856	(1,752)	201,536	185,319	52,865	149,220	202,085	37,658	175,093	(10,667)
2015	863,825	425,856	(1,822)	201,536	186,605	51,650	149,220	200,870	20,926	185,173	(5,229)
2016	863,825	425,856	(1,891)	201,536	192,105	46,218	149,220	195,438	16,396	185,370	(6,328)

Table 7: continued

YEAR COMBINED CUMULATIVE	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C AC INTERTIE CAPACITY OWNERSHIP CAPITAL PAYMENTS (REV REQ STUDY DOC,Chapter 8)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	J NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	K NET POSITION (K=H-I-J)
2017	863,825	425,856	(1,962)	201,536	198,092	40,304	149,220	189,524	1	200,053	(10,530)
2018	863,825	425,856	(2,038)	201,536	202,274	36,197	149,220	185,417	5,355	191,649	(11,587)
2019	863,825	425,856	(2,117)	201,536	210,784	27,767	149,220	176,987	183,831	4,837	(11,681)
2020	863,825	425,856	(2,196)	201,536	207,023	31,606	149,220	180,826	172,915	19,588	(11,677)
2021	863,825	425,856	(2,279)	201,536	210,548	28,164	149,220	177,384	168,495	20,567	(11,677)
2022	863,825	425,856	(2,365)	201,536	206,134	32,664	149,220	181,884	171,970	21,592	(11,677)
2023	863,825	425,856	(2,444)	201,536	212,951	25,926	149,220	175,146	164,144	22,674	(11,672)
2024	863,825	425,856	(2,527)	201,536	213,979	24,981	149,220	174,201	168,233	17,637	(11,669)
2025	863,825	425,856	(2,606)	201,536	212,454	26,585	149,220	175,805	187,473	0	(11,668)
2026	863,825	425,856	(2,678)	201,536	210,838	28,274	149,220	177,494	189,161	0	(11,667)
2027	863,825	425,856	(2,742)	201,536	218,943	20,233	149,220	169,453	181,115	0	(11,662)
2028	863,825	425,856	(2,797)	201,536	212,941	26,289	149,220	175,509	187,167	0	(11,658)
2029	863,825	425,856	(2,839)	201,536	222,510	16,762	149,220	165,982	177,639	0	(11,656)
2030	863,825	425,856	(2,873)	201,536	223,086	16,220	149,220	165,440	177,096	0	(11,656)
2031	863,825	425,856	(2,889)	201,536	221,930	17,392	149,220	166,612	178,263	0	(11,650)
2032	863,825	425,856	(2,882)	201,536	223,572	15,743	149,220	164,963	176,609	0	(11,646)
2033	863,825	425,856	(2,868)	201,536	230,899	8,402	149,220	157,622	140,174	29,896	(12,448)
2034	863,825	425,856	(2,830)	201,536	234,913	4,350	149,220	153,570	79,571	89,689	(15,689)
2035	863,825	425,856	(2,779)	201,536	241,438	(2,226)	149,220	146,994	164,367	0	(17,372)
2036	863,825	425,856	(2,719)	201,536	247,521	(8,368)	149,220	140,852	139,751	15,255	(14,155)
2037	863,825	425,856	(2,650)	201,536	247,678	(8,596)	149,220	140,624	18,437	134,997	(12,810)
2038	863,825	425,856	(2,625)	201,536	260,252	(21,194)	149,220	128,026	24,340	125,879	(22,193)
2039	863,825	425,856	(2,490)	201,536	269,760	(30,837)	149,220	118,383	119,919	2,934	(4,470)
2040	863,825	425,856	(2,418)	201,536	262,116	(23,265)	149,220	125,955	144,982		(19,027)
2041	863,825	425,856	(2,350)	201,536	263,680	(24,897)	149,220	124,323	136,275		(11,952)
2042	863,825	425,856	(2,286)	201,536	264,148	(25,429)	149,220	123,791	135,535		(11,744)
2043	863,825	425,856	(2,229)	201,536	269,570	(30,908)	149,220	118,312	130,056		(11,744)
2044	863,825	425,856	(2,184)	201,536	275,302	(36,685)	149,220	112,535	124,279		(11,744)
2045	863,825	425,856	(2,147)	201,536	281,446	(42,866)	149,220	106,354	118,093		(11,739)
2046	863,825	425,856	(2,121)	201,536	290,875	(52,321)	149,220	96,899	108,643		(11,744)
TRANSMISSION TOTALS	47,776,354	22,625,325	(83,693)	11,152,996	12,966,787	1,114,939	9,002,230	11,445,036	7,604,781	1,665,428	72,186

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

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

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

4/INCREASED BY 156,000 AC INTERTIE CAPACITY OWNERSHIP PAYMENT.

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

Table 8: Revised Revenue Test Income Statement

($000s)

		A FY 2010	B FY 2011
1	REVENUES FROM PROPOSED RATES	851,739	880,361
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	117,472	119,695
4	TRANSMISSION MAINTENANCE	127,306	132,346
5	TRANSMISSION ENGINEERING	23,540	23,675
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	103,328	116,422
7	BPA INTERNAL SUPPORT	65,312	65,716
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(8,000)	(32,000)
9	DEPRECIATION & AMORTIZATION	189,702	201,536
10	TOTAL OPERATING EXPENSES	618,661	627,390
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	32,979	27,538
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	90,812	112,508
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
17	DEBT SERVICE REASSIGNMENT INTEREST	56,781	56,780
18	NON-FEDERAL INTEREST	32,814	40,878
19	AFUDC	(16,501)	(22,648)
20	INTEREST INCOME	(24,655)	(24,673)
21	NET INTEREST EXPENSE	154,020	172,107
22	TOTAL EXPENSES	772,681	799,498
23	NET REVENUES	79,058	80,863

Table 9: Revised Revenue Test Statement of Cash Flows

($000s)

		A FY 2010	B FY 2011
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	79,058	80,863
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	189,702	201,536
5	NON-FEDERAL PROJECTS DEBT SERVICE	10,696	13,057
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
9	ACCRUAL REVENUES (AC INTERTIE/FIBER/LGIA)	(41,537)	(47,097)
10	CASH PROVIDED BY CURRENT OPERATIONS	234,710	245,083
11	CASH USED FOR CAPITAL INVESTMENTS:		
12	INVESTMENT IN:		
13	UTILITY PLANT	(443,957)	(454,575)
14	CASH USED FOR CAPITAL INVESTMENTS	(443,957)	(454,575)
15	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
16	INCREASE IN LONG-TERM DEBT	428,957	439,575
17	DEBT SERVICE REASSIGNMENT PRINCIPAL	(12)	(154)
18	REPAYMENT OF LONG-TERM DEBT	(140,251)	(100,000)
19	REPAYMENT OF CAPITAL APPROPRIATIONS	(74,905)	(124,707)
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	213,790	214,714
21	**ANNUAL INCREASE (DECREASE) IN CASH**	**4,542**	**5,223**

Table 10: Transmission 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)	AC INTERTIE CAPACITY OWNERSHIP CAPITAL PAYMENTS (REV REQ STUDY DOC,Chapter 8)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	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
TRANSMISSION											
1978	116,430	69,767		51,503	60,337	(65,177)	51,503	(13,674)	194		(13,868)
1979	107,017	73,801		53,756	69,112	(89,652)	53,756	(35,896)	26		(35,922)
1980	170,603	77,594		55,613	78,039	(40,643)	55,613	14,970	2		14,968
1981	202,740	87,243		59,638	87,665	(31,806)	59,638	27,832	1,236 **2/**		26,596
1982	269,200	91,562		64,458	106,190	6,990	64,458	71,448	0		71,448
1983	359,641	99,520		67,969	138,268	53,884	67,969	121,853	0		121,853
1984	417,821	101,406		60,360	158,783	97,272	60,360	157,632	26,722 **3/**		130,910
1985	510,030	141,623		71,012	160,336	137,059	71,012	208,071	199,646		8,425
1986	446,435	144,438		77,574	178,460	45,963	77,574	123,537	180,915		(57,378)
1987	456,728	148,596		85,807	177,020	45,305	85,807	131,112	148,860		(17,748)
1988	405,154	167,102		90,076	164,131	(16,155)	90,076	73,921	44,757		29,164
1989	422,202	175,240		93,076	164,044	(10,158)	93,076	82,918	119,322		(36,404)
1990	426,855	183,512		98,881	153,440	(8,978)	98,881	89,903	99,460		(9,557)
1991	439,871	199,668		98,731	139,458	2,014	98,731	100,745	70,930		29,815
1992	428,769	209,868		101,946	143,789	(26,834)	101,946	75,112	190,864		(115,752)
1993	417,555	189,926		101,929	173,271	(47,571)	101,929	54,358	130,989		(76,631)
1994	462,511	202,309		103,956	179,052	(22,806)	103,956	81,150	55,977		25,173
1995	490,264	200,501		112,940	181,744	(4,921)	112,940	264,019 **/4**	281,789		(17,770)
1996	534,456	206,128		125,961	165,175	37,192	123,219	145,411 **/5**	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	109,802	114,383	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	117,884	129,855	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	133,779	133,753	139,784		(6,031)
2000	578,340	270,153		154,069	165,330	(11,212)	135,358	124,146	114,587		9,559
2001	646,673	282,851		154,881	165,404	43,537	151,746	195,283	59,064		136,219
2002	720,382	364,511		161,042	150,718	44,111	148,912	193,023	131,667		61,356
2003	663,601	326,248		171,129	168,996	(2,772)	160,628	473,056	470,747		2,309
2004	644,059	313,994		204,445	137,822	(12,202)	225,406	403,481 **/5**	359,500		43,981
2005	634,530	333,584		189,501	135,754	(24,309)	169,180	320,071 **/5**	345,201		(25,130)
2006	784,339	378,872		171,359	136,761	97,347	145,949	432,634 **/5**	384,947		47,687
2007	808,624	372,556		175,584	133,806	126,678	146,762	460,240 **/5**	372,100	716	87,424
2008	844,215	382,879		174,599	136,360	150,377	139,327	384,756 **/5**	277,833	4,510	102,413
COST EVALUATION PERIOD											
2009	830,968	412,684		179,440	126,212	112,632	132,479	280,111 **/5**	222,659	10,407	47,045
RATE APPROVAL PERIOD											
2010	851,739	428,959		189,702	154,020	79,058	140,652	219,710	215,156	12	4,542
2011	880,361	425,856		201,536	172,107	80,862	149,222	230,084	224,707	154	5,223
REPAYMENT PERIOD											
2012	880,361	425,856	(1,616)	201,536	181,632	72,953	153,663	226,616	175,106	41,118	10,392
2013	880,361	425,856	(1,682)	201,536	183,872	70,779	153,663	224,442	47,854	165,628	10,960
2014	880,361	425,856	(1,752)	201,536	184,102	70,618	153,663	224,281	37,658	175,093	11,529
2015	880,361	425,856	(1,822)	201,536	185,388	69,403	153,663	223,066	20,926	185,173	16,967
2016	880,361	425,856	(1,891)	201,536	190,888	63,971	153,663	217,634	16,396	185,370	15,868

Table 10: continued

	A	B	C	D	E	F	G	H	I	J	K
YEAR COMBINED CUMULATIVE	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	AC INTERTIE CAPACITY OWNERSHIP CAPITAL PAYMENTS (REV REQ STUDY DOC,Chapter 8)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	NET POSITION (K=H-I-J)
2017	880,361	425,856	(1,962)	201,536	196,875	58,057	153,663	211,720	1	200,053	11,666
2018	880,361	425,856	(2,038)	201,536	201,057	53,950	153,663	207,613	5,355	191,649	10,609
2019	880,361	425,856	(2,117)	201,536	209,567	45,520	153,663	199,183	183,831	4,837	10,515
2020	880,361	425,856	(2,196)	201,536	205,806	49,359	153,663	203,022	172,915	19,588	10,519
2021	880,361	425,856	(2,279)	201,536	209,331	45,917	153,663	199,580	168,495	20,567	10,519
2022	880,361	425,856	(2,365)	201,536	204,917	50,417	153,663	204,080	171,970	21,592	10,519
2023	880,361	425,856	(2,444)	201,536	211,734	43,679	153,663	197,342	164,144	22,674	10,524
2024	880,361	425,856	(2,527)	201,536	212,762	42,734	153,663	196,397	168,233	17,637	10,527
2025	880,361	425,856	(2,606)	201,536	211,237	44,338	153,663	198,001	187,473	0	10,528
2026	880,361	425,856	(2,678)	201,536	209,621	46,027	153,663	199,690	189,161	0	10,529
2027	880,361	425,856	(2,742)	201,536	217,726	37,986	153,663	191,649	181,115	0	10,534
2028	880,361	425,856	(2,797)	201,536	211,724	44,042	153,663	197,705	187,167	0	10,538
2029	880,361	425,856	(2,839)	201,536	221,293	34,515	153,663	188,178	177,639	0	10,540
2030	880,361	425,856	(2,873)	201,536	221,869	33,973	153,663	187,636	177,096	0	10,540
2031	880,361	425,856	(2,889)	201,536	220,713	35,145	153,663	188,808	178,263	0	10,546
2032	880,361	425,856	(2,882)	201,536	222,355	33,496	153,663	187,159	176,609	0	10,550
2033	880,361	425,856	(2,868)	201,536	229,682	26,155	153,663	179,818	140,174	29,896	9,748
2034	880,361	425,856	(2,830)	201,536	233,696	22,103	153,663	175,766	79,571	89,689	6,507
2035	880,361	425,856	(2,779)	201,536	240,221	15,527	153,663	169,190	164,367	0	4,824
2036	880,361	425,856	(2,719)	201,536	246,304	9,385	153,663	163,048	139,751	15,255	8,041
2037	880,361	425,856	(2,650)	201,536	246,461	9,157	153,663	162,820	18,437	134,997	9,386
2038	880,361	425,856	(2,625)	201,536	259,035	(3,441)	153,663	150,222	24,340	125,879	3
2039	880,361	425,856	(2,490)	201,536	268,543	(13,084)	153,663	140,579	119,919	2,934	17,726
2040	880,361	425,856	(2,418)	201,536	260,899	(5,512)	153,663	148,151	144,982		3,169
2041	880,361	425,856	(2,350)	201,536	262,463	(7,144)	153,663	146,519	136,275		10,244
2042	880,361	425,856	(2,286)	201,536	262,931	(7,676)	153,663	145,987	135,535		10,452
2043	880,361	425,856	(2,229)	201,536	268,353	(13,155)	153,663	140,508	130,056		10,452
2044	880,361	425,856	(2,184)	201,536	274,085	(18,932)	153,663	134,731	124,279		10,452
2045	880,361	425,856	(2,147)	201,536	280,229	(25,113)	153,663	128,550	118,093		10,457
2046	880,361	425,856	(2,121)	201,536	289,658	(34,568)	153,663	119,095	108,643		10,452
TRANSMISSION TOTALS	48,380,024	22,625,325	(83,693)	11,152,996	12,923,204	1,762,192	9,157,735	12,247,794	7,604,781	1,665,428	874,944

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

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

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

4/INCREASED BY 156,000 AC INTERTIE CAPACITY OWNERSHIP PAYMENT.

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

Table 11: Amortization of Transmission Investments Over Repayment Period

($000s)

	A	B	C	D	E	F	G	H
1	Investment Placed in Service							
2	Fiscal Year	Initial Project	Replacements	Cumulative Amount in Service	Due Amortization	Discretionary Amortization	UnAmortized Investment	Term Investment Schedule
3	2008	1,910,316	-	1,910,316	-	-	1,910,316	5,212,968
4	2009	336,473	-	2,246,789	189,599	23,060	2,034,130	5,128,369
5	2010	373,881	-	2,408,011	144,035	71,121	2,192,855	5,355,748
6	2011	383,748	-	2,576,603	121,232	103,475	2,351,897	5,597,083
7	2012	-	115,308	2,467,205	44,358	130,748	2,292,099	5,543,022
8	2013	-	107,672	2,399,771	18,250	29,604	2,351,917	5,572,150
9	2014	-	108,064	2,459,981		37,658	2,422,323	5,482,590
10	2015	-	108,477	2,530,800		20,926	2,509,874	5,430,750
11	2016	-	108,886	2,618,760		16,396	2,602,364	5,363,268
12	2017	-	109,362	2,711,726		1	2,711,725	5,146,658
13	2018	-	109,900	2,821,625		5,355	2,816,270	5,079,794
14	2019	-	110,498	2,926,768		183,831	2,742,937	5,099,953
15	2020	-	111,150	2,854,087	50,000	122,915	2,681,172	5,148,249
16	2021	-	111,854	2,793,026	0	168,495	2,624,532	5,269,571
17	2022	-	112,606	2,737,138	95,000	76,970	2,565,168	5,354,431
18	2023	-	100,236	2,665,404		164,144	2,501,260	5,545,604
19	2024	-	89,375	2,590,635		168,233	2,422,402	5,739,996
20	2025	-	79,794	2,502,196	63,617	123,856	2,314,723	5,817,866
21	2026	-	71,349	2,386,072	124,739	64,422	2,196,911	6,013,187
22	2027	-	63,909	2,260,820		181,115	2,079,705	6,215,612
23	2028	-	57,284	2,136,989	162,300	24,867	1,949,822	6,151,228
24	2029	-	51,431	2,001,253		177,639	1,823,614	6,341,343
25	2030	-	46,309	1,869,923	30,000	147,096	1,692,827	6,413,890
26	2031	-	41,752	1,734,579	106,500	71,763	1,556,316	6,321,219
27	2032	-	37,729	1,594,045	148,401	28,208	1,417,437	5,979,800
28	2033	-	53,903	1,471,340	40,000	100,174	1,331,166	5,517,122
29	2034	-	54,394	1,385,560	40,000	39,571	1,305,989	5,425,312
30	2035	-	54,930	1,360,919	125,000	39,367	1,196,552	5,506,076
31	2036	-	55,449	1,252,001		139,751	1,112,251	5,710,954
32	2037	-	56,012	1,168,263		18,437	1,149,826	5,879,758
33	2038	-	56,614	1,206,440		24,340	1,182,100	6,082,440
34	2039	-	57,258	1,239,358		119,919	1,119,439	6,284,082
35	2040	-	57,881	1,177,320	105,000	39,982	1,032,338	6,484,799
36	2041	-	58,542	1,090,880		136,275	954,604	6,684,798
37	2042	-	59,240	1,013,844		135,535	878,309	6,884,286
38	2043	-	55,810	934,119		130,056	804,064	7,083,595
39	2044	-	52,583	856,647		124,279	732,368	7,213,124
40	2045	-	49,603	781,971	118,093		663,878	6,973,800
41	2046	-	46,806	710,684	-	108,643	602,040	6,725,024

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FIGURES

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Figure 1: Transmission Revenue Requirement Process

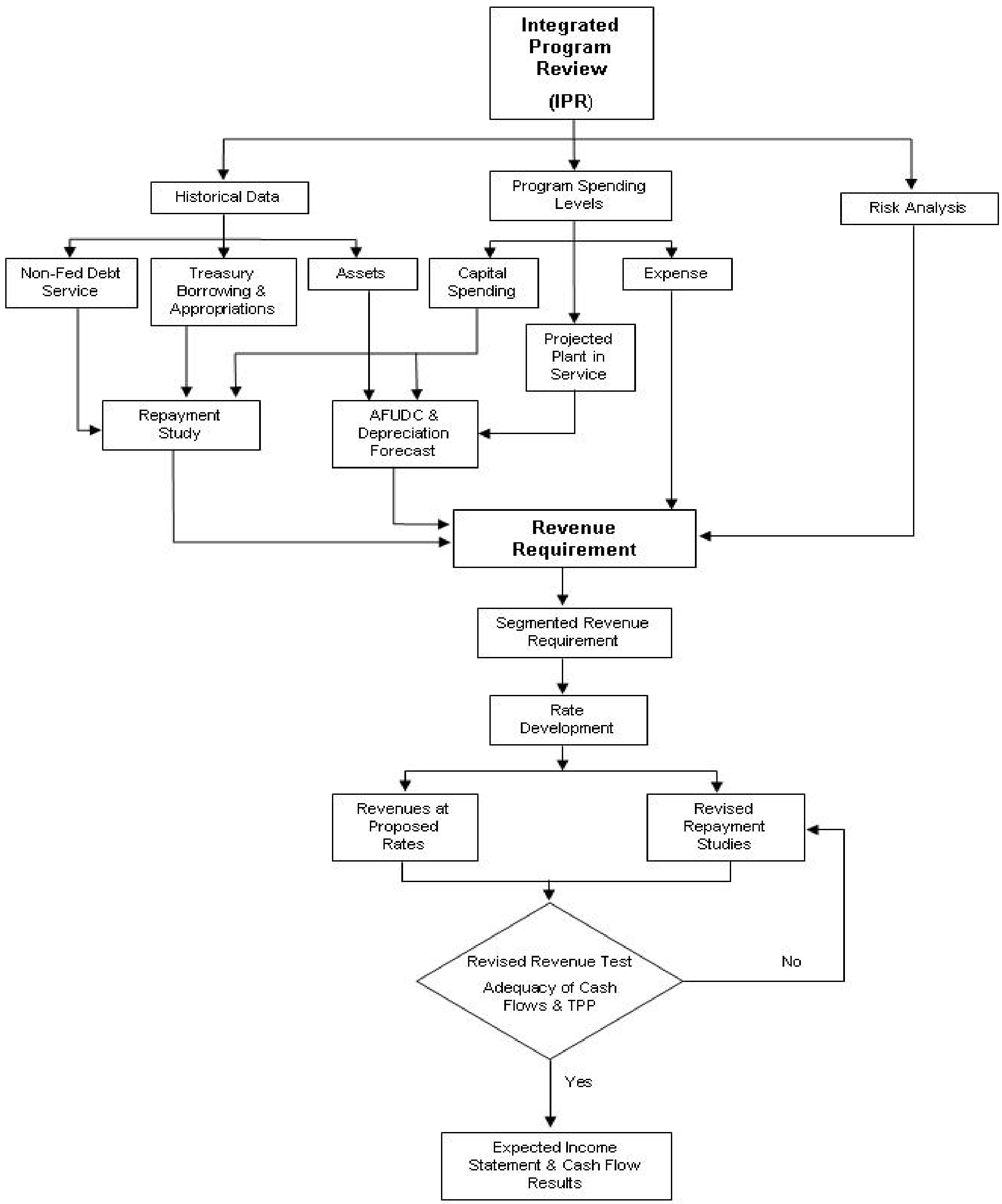
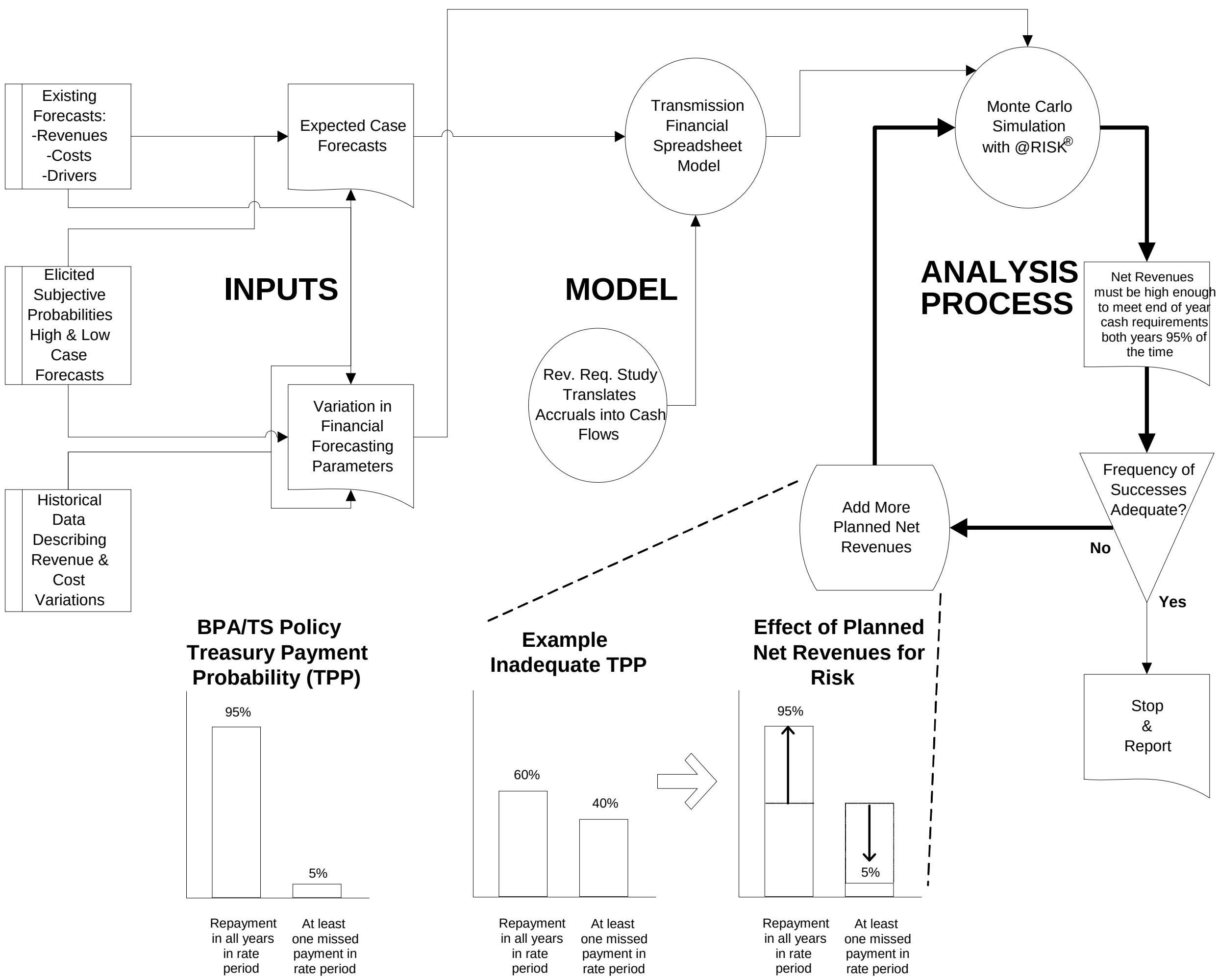


Figure 2: Transmission Rate Case Risk Analysis Flow Diagram



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APPENDIX A

Integrated Program Review

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Department of Energy

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

FINANCE

November 14, 2008

In reply refer to: F-2

To Our Customers, Constituents, Tribes and Other Stakeholders:

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

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

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

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

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

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

Sincerely,

/s/ David J. Armstrong November 14, 2008

David J. Armstrong
Executive Vice President and Chief Financial Officer

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

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

Final Report
November 14, 2008

BONNEVILLE
POWER ADMINISTRATION

Section 1

Background
and
Summary of Decisions

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

Background

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

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

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

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

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

Summary of Decisions

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

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

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

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

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

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

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

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

For FY 2009:

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

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

For FY 2010-2011:

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

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

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

Additional Review

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

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

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

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

FY 2010-11 Power Expenses Summary

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

*These will be determined in the upcoming rate case.

FY 2009 Power Expenses Summary

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

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

FY 2010-11 Power Capital Summary

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

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2009 Power Capital Summary

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

$ in Thousands	2009 in WP-07 Rate Case	Supplemental Rate Case	Initial IPR	Final IPR	Change Between Initial IPR and Final IPR
Description	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**
Corps of Engineers/Bureau of Reclamation	137,000	137,000	154,950	154,950	0
Fish & Wildlife	36,000	36,000	50,000	50,000	0
Conservation	32,000	32,000	42,000	32,000	-10,000
CGS	27,700	27,700	96,700	96,700	0
CRFM	62,400	62,400	63,000	111,000	48,000
15% lapse factor1/			(29,813)	(28,313)	1,500
Total Capital	295,100	295,100	376,837	416,337	39,500

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2010-11 Transmission Expense Summary

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

*These will be determined in the upcoming rate case.

FY 2010-11 Transmission Capital Summary

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

Response to General Comments

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. Levelizing Costs:

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

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

3. IPR Process:

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

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

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

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

4. Tier 2 Product:

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

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

Structure of This Report

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

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

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

Section 2

POWER SERVICES

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

FY 2010-11 Power Expenses Summary

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Fish & Wildlife	70,000	70,000	0	60,000	60,000	0
Conservation	56,000	38,000	(18,000)	56,000	46,000	(10,000)
CGS	73,600	73,600	0	99,900	99,900	0
CRFM	88,000	88,000	0	96,000	96,000	0
17% Lapse Factor [1/]	(36,150)	(36,150)	0	(38,550)	(38,550)	0
Total Capital	280,700	280,700	(18,000)	296,461	296,461	(10,000)

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2009 Power Expenses Summary

(As reported in the 2009 Power Close Out Report)

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

FY 2009 Power Capital Summary

(As reported in the 2009 Power Close Out Report)

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

1/ Excludes CGS, CRFM, Fish & Wildlife

A. COLUMBIA GENERATING STATION O&M

$ millions

Expense

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

Capital

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

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

Comments Received:

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

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

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

3) Performance improvement initiatives.

These investments should result in improved overall performance of CGS.

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

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

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

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

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

B. CORPS AND RECLAMATION O&M

$ millions

Expense

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

Capital

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

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

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

Comments Received:

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

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

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

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

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

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

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

C. LONG-TERM GENERATING PROGRAM

$ millions

Expense

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

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

Comments Received:

None

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

D. ENERGY EFFICIENCY & CONSERVATION

$ millions

Expense

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

Capital

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

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

(As reported in the 2009 Power Close Out Report)

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

Comments Received:

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

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

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

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

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

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

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

E. FISH AND WILDLIFE DIRECT PROGRAM

$ millions

Expense

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

Capital

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

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

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

Comments Received:

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

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

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

Program Review:

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

Science Review:

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

Economic Review:

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

Cultural Resources:

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

Mitigation Settlement of Southern Idaho and Albeni Falls:

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

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

Cost Effectiveness, Duplication and Unnecessary Efforts:

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

1) The Program itself must be firmly grounded in measurable performance expectations expressed as biological and environmental objectives; and

2) Projects must be designed around discrete work elements tailored to expected outcomes that are explicitly addressed to the Program's performance objectives.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

$ millions

Expense

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

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

Comments Received:

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

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

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

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

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

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

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

G. RENEWABLE RESOURCES

$ millions

Expense

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

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

Comments Received:

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

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

- CRTIFC supports full funding of renewable resource programs.

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

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

H. POWER INTERNAL COSTS/ POST-RETIREMENT BENEFITS

$ millions

Expense

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

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

(As reported in the 2009 Power Close Out Report)

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

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

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

There was no change in Post-Retirement Benefits.

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

COST DECISIONS TO BE MADE AS PART OF THE RATE CASE

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

I. POWER PURCHASES, INCLUDING MONETIZED BENEFITS TO DSIs

$ millions

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

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

J. TRANSMISSION PURCHASES, RESERVE/ANCILLARY SERVICES

$ millions

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

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

K. RESIDENTIAL EXCHANGE PROGRAM

$ millions

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

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

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

$ millions

Net Interest

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

Amortization/Depreciation

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

Non-Federal Debt Service

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

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

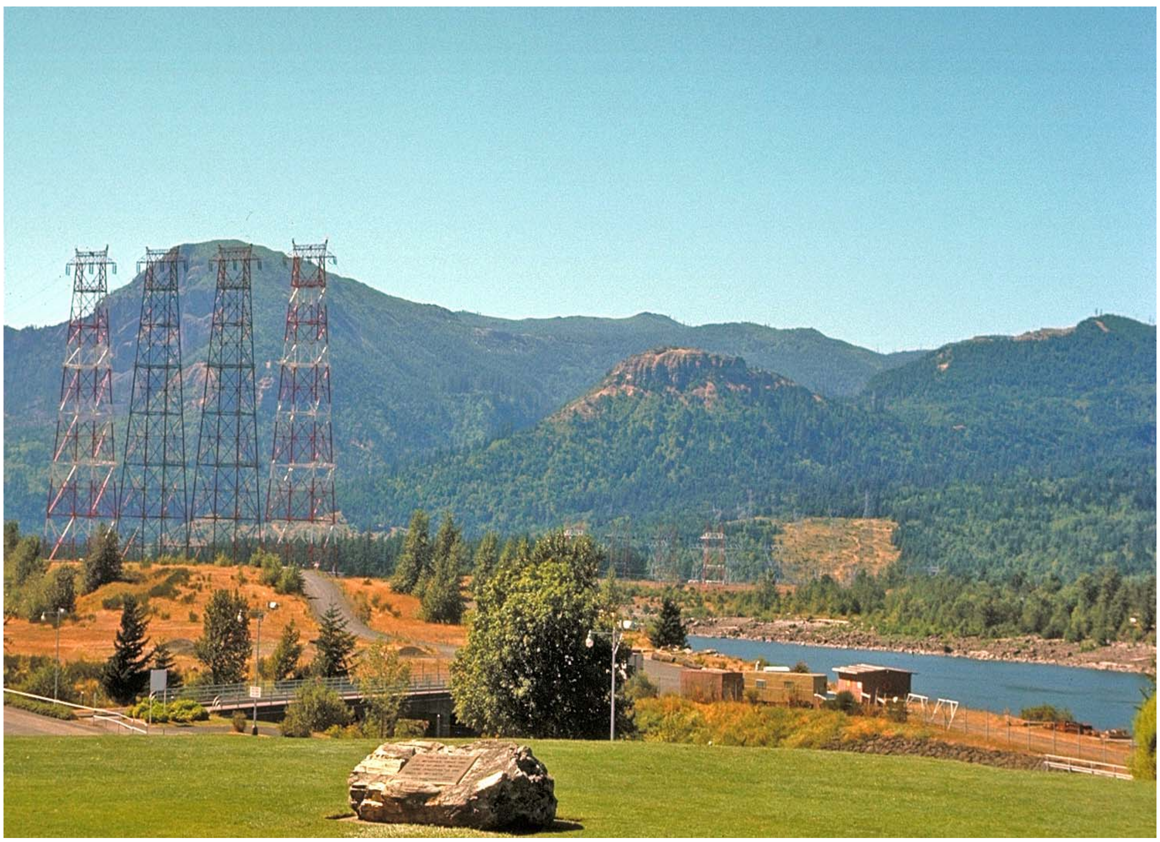
Decision: Changes since the initial IPR numbers reflect the decisions described above related to the decreased Conservation capital for FY 2010 and 2011. Other changes that affect the current estimates are revised estimates of FY 2008 investments and revised reserves estimates resulting in different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

M. DEBT MANAGEMENT

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

Section 3

TRANSMISSION



FY 2010-11 Transmission Expense Summary

$ thousands

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

*These will be determined in the upcoming rate case.

FY 2010-11 Transmission Capital Summary

$ in Thousands

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

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

A. TRANSMISSION OPERATIONS

$ millions

Expense

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

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

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

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

B. TRANSMISSION MAINTENANCE: SYSTEM MAINTENANCE AND ENVIRONMENTAL OPERATIONS

$ millions

Expense

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

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

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

C. TRANSMISSION ENGINEERING

$ millions

Expense

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

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

Comments Received on Transmission Expenses Generally:

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

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

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

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

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

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

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

The drivers for the increases in Transmission Operations are:

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

The increased funding will be used to:

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

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

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

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

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

D. AGENCY SERVICES/PENSION/POST-RETIREMENT BENEFITS

$ millions

Expense

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

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

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

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

E. TRANSMISSION CAPITAL

$ millions

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

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

Comments Received:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

COST DECISIONS TO BE MADE AS PART OF THE RATE CASE

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

F. TRANSMISSION ACQUISITION AND ANCILLARY SERVICES

$ millions

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

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

Includes 3rd party only

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

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

$ millions

Net Interest

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

Amortization/Depreciation

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

Non-Federal Debt Service

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

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

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

H. DEBT MANAGEMENT

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

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

Section 4
AGENCY SERVICES

AGENCY SERVICES

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

Some of the larger programs and their drivers are:

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

Comments Received:

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

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

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

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

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

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

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

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

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

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

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

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

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

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
$ in thousands	FY 2009	FY 2009	FY 2009
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	
$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
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	IPR1		Final IPR2 Decisions				
$ in thousands	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	
$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
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	IPR1		Final IPR2 Decisions				
$ in thousands	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	IPR1		Final IPR2 Decisions				
$ in thousands	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.

$ in thousands	IPR1 FY 2010	IPR1 FY 2011	Final IPR2 Decisions FY 2010	Final IPR2 Decisions FY 2011	Change FY 2010	Change FY 2011
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	
$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
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	
$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
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	
$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
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 the1970s.

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	
$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
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	
$ in thousands	FY 2010	FY 2011	FY 2010	FY 2011	FY 2010	FY 2011
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 Study Tables

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DESCRIPTION OF REPAYMENT PROGRAM TABLES

Appendix B is being discontinued. Most 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 Repayments to the U.S. Treasury, contains all of the information previously displayed in Table 11 of this Appendix. The new Table 11, Amortization of Transmission Investments Over the Repayment Period, contains the information previously found in Table 13A in this Appendix.

Information on the principal and interest payments and the application of amortization for Federal investments can be found in the Documentation. *See*, Documentation, TR-10-FS-BPA-01A, Chapter 11.

Information on the principal and interest components of non-Federal payment obligations can be found in Chapter 7 of the Documentation.

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