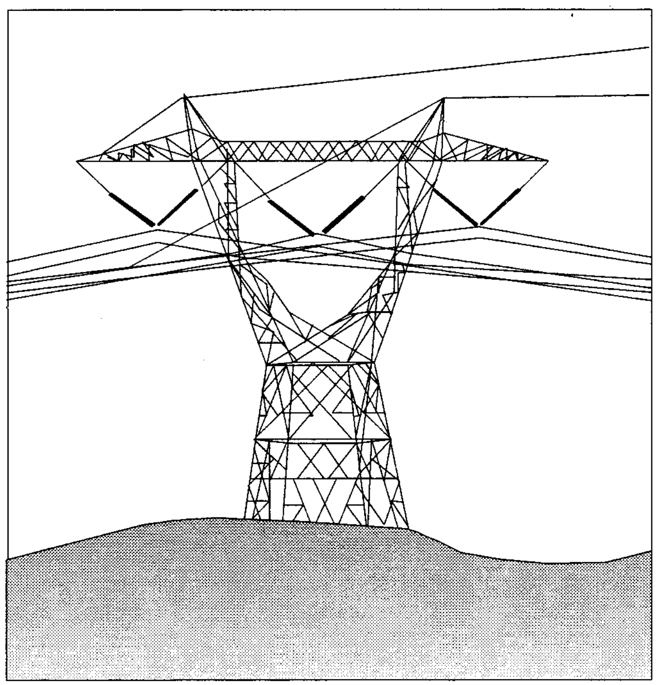
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE

2002 FINAL TRANSMISSION PROPOSAL

REVENUE REQUIREMENT STUDY

TR-02-FS-BPA-01



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AUGUST 2000

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COMMONLY USED ACRONYMS

AC	Alternating Current
ACS	Ancillary Services and Control Area Services (Rate)
AF	Advance Funding (Rate)
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
ASC	Average System Cost
BOR	U.S. Bureau of Reclamation
BPA	Bonneville Power Administration
Btu	British Thermal Unit
CA	Control Area
CAISO	California Independent System Operator
California PX	California Power Exchange
CAS	Control Area Service
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
CPTC	Columbia Power Trades Council
CRAC	Cost Recovery Adjustment Clause
CSL	Customer-Served Load
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DOE	Department of Energy
DOI	Department of Interior
DSIs	Direct Service Industrial Customers
EIA	Energy Information Administration
Energy Northwest	Formerly Washington Public Power Supply System Project
F&O	Financial and Operating Reports
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FPT	Formula Power Transmission Rate
FTE	Full-time Equivalent
FY	Fiscal Year (Oct-Sep)
GDP	Gross Domestic Product
GI	Generation Integration
GRSPs	General Rate Schedule Provisions
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatthour
HLH	Heavy Load Hours
HNF	Hourly Non-Firm
IDC	Interest During Construction

IE	Eastern Intertie (Rate)
IM	Montana Intertie (Rate)
IOUs	Investor-Owned Utilities
IP	Industrial Firm Power (Rate)
IR	Integration of Resources (Rate)
IS	Southern Intertie (Rate)
ISC	Investment Service Coverage
ISO	Independent System Operator
kcfs	kilo (thousands) of cubic feet per second
kV	Kilovolt (1000 volts)
kVAr	Kilovoltampere Reactive
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LLH	Light Load Hours
m/kWh	Mills per Kilowatthour
MAF	Million Acre Feet
MORC	Minimum Operating Reliability Criteria
MTPL	Monthly Transmission Peak Load
MW	Megawatt (1 million watts)
MWh	Megawatthour
NCD	Network Contract Demand (Service and Rate)
NERC	North American Electric Reliability Council
NF	Nonfirm Energy
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NT	Network Integration Transmission (Service and Rate)
NTSA	Non-Treaty Storage Agreement
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
O&M	Operation and Maintenance
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OMB	Office of Management and Budget
OY	Operating Year (Aug-Jul)
PA	Public Agency
PBL	Power Business Line
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration (or, Interconnection)
POR	Point of Receipt
PSW	Pacific Southwest
PTP	Point to Point (Service and Rate)

PUD	Public or People's Utility District
Reclamation	Bureau of Reclamation
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase Sale Agreement
RRS	Revenue Requirement Study
RTO	Regional Transmission Organization
SCADA	Supervisory Control And Data Acquisition System
Tariff	Open Access Transmission Tariff
TBL	Transmission Business Line
TCH	Transmission Contract Holder
TGT	Townsend-Garrison Transmission (Rate)
TPP	Treasury Payment Probability
TRAP	Transmission Risk Analysis Processor
TRS	Transmission Rate Study
TTSL	Total Transmission System Loading
UIC	Unauthorized Increase Charge
UFT	Use of Facilities (Rate)
USBOR	U.S. Bureau of Reclamation
VOR	Value of Reserves
WEFA	Wharton Econometric Forecasting Associates
WSCC	Western Systems Coordinating Council
WSPP	Western System Power Pool
1CP	One Coincidental Peak
12CP	Twelve Coincidental Peak

1. INTRODUCTION

1.1 Purpose and Development of the Transmission Revenue Requirement Study

The purpose of the Transmission Revenue Requirement Study (Study) is to establish the level of revenues needed from rates for 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 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 transmission and ancillary services; the cost of generation inputs for ancillary services and other interbusiness-line services necessary for the transmission of power; planned net revenues for risk, and all other transmission-related costs incurred by the Administrator.

The cost evaluation period for this rate proposal includes Fiscal Years (FY) 2000 - 2003, the period extending from the last year for which historical information is available through the proposed rate test period. The Study is based on transmission revenue requirements for the rate test period FY 2002 – 2003, including the results of transmission repayment studies. This Study does ***not*** include revenue requirements or a cost recovery demonstration for the Bonneville Power Administration's (BPA) generation function. BPA's generation revenue requirements were developed in a separate rate proceeding to establish BPA's wholesale power rates which began on August 24, 1999, and concluded with a Record of Decision, issued May 10, 2000.

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 (Documentation) contains key technical assumptions and calculations, the results of the transmission repayment studies, and a further explanation of the repayment program and its outputs. The Documentation appears in TR-02-FS-BPA-01A

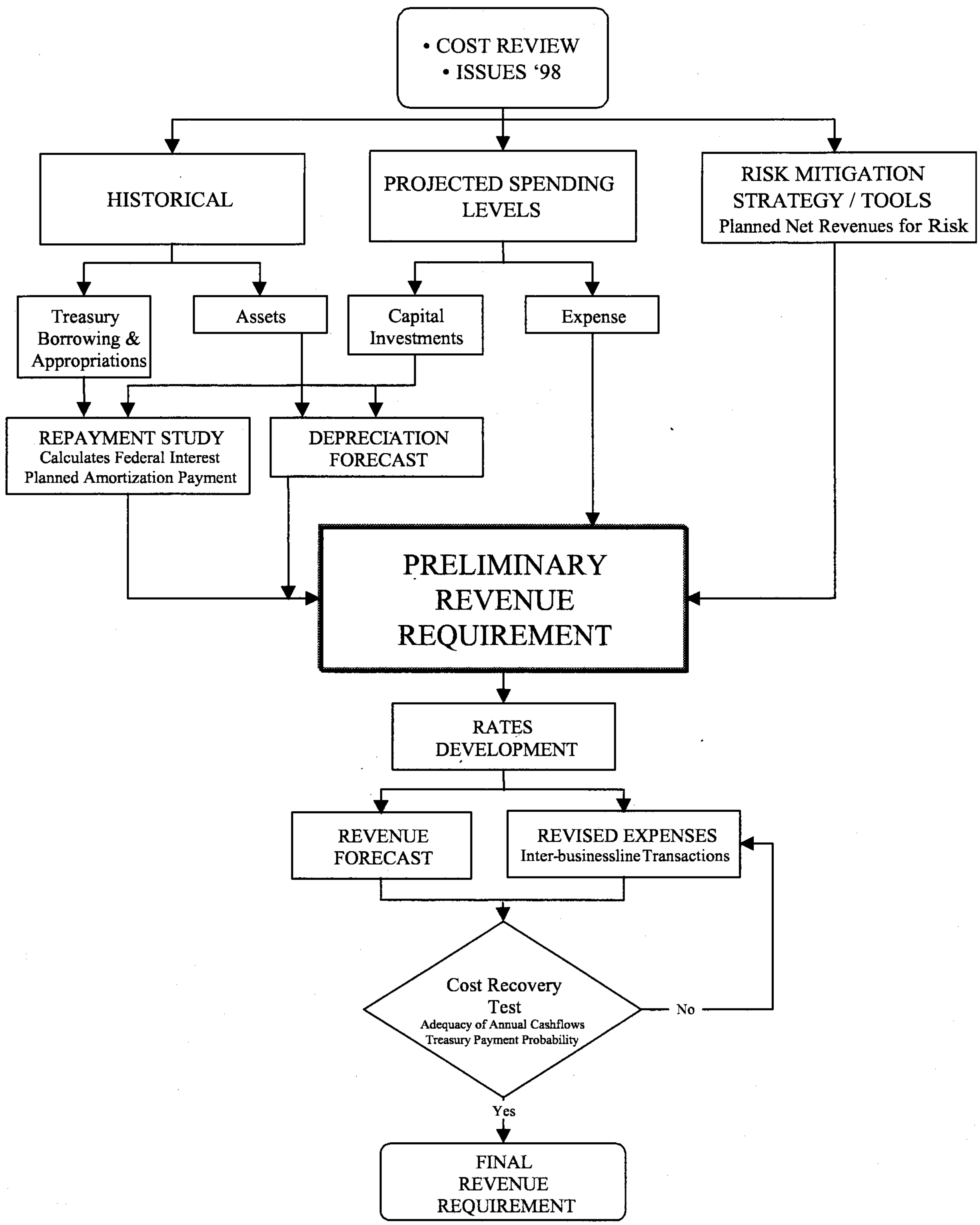
The revenue requirements that appear in this Study are developed using a cost accounting analysis comprised of three parts. First, repayment studies for the transmission function are prepared to determine the amortization schedule and to project annual interest expense for bonds and appropriations that fund the Federal investment in transmission and transmission-related assets. Repayment studies are conducted for each year of the rate test period, and cover a 35-year repayment period. Second, transmission operating expenses and minimum required net revenues (if needed) are projected for each year of the rate test period. Third, annual planned net revenues for risk are determined taking into account risks, BPA's cost recovery goals, and risk mitigation measures. From these three steps, revenue requirements are set at the revenue level necessary to fulfill BPA's cost recovery requirements and objectives. See Figure 1.1, Transmission Revenue Requirement Process.

BPA conducts a current revenue test to determine whether revenues projected from current 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, contained in Chapter 4.2 of this study, demonstrates that current revenues are insufficient to meet cost recovery requirements and objectives for the rate test period and the repayment period.

Consistent with RA 6120.2 and the FERC rate review standards applicable to BPA, BPA must demonstrate the adequacy of the proposed rates to recover its costs. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements

FIGURE 1.1

TRANSMISSION REVENUE REQUIREMENT PROCESS



and objectives for the rate test and repayment period. The revised revenue test, contained in Chapter 4.3 of this Study, demonstrates that revenues from the proposed transmission and ancillary services rates will recover transmission costs in each year of the rate test period and over the ensuing 35-year repayment period. Consistent with the Treasury payment probability (TPP) standard that was adopted as a long-term policy in 1993, the costs are projected to be recovered through the transmission and ancillary services rates with a greater than 95 percent probability that associated United States (U.S.) Treasury payments will be made on time and in full over the two-year rate period. See Chapter 2.2 of this Study.

Table 1.1 summarizes the revised revenue test and shows projected net revenues from proposed rates 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 1.1

PROJECTED NET REVENUES FROM PROPOSED RATES
($000s)

Fiscal Year		Transmission
2002	Projected Revenues From Proposed Rates	$674,822
	Projected Expenses	$671,182
	Net Revenues	**$3,640**
2003	Projected Revenues From Proposed Rates	$685,689
	Projected Expenses	$679,105
	Net Revenues	**$6,584**
Average FYs 2002-2003	**Projected Revenues From Proposed Rates**	**$680,256**
	Projected Expenses	**$675,144**
	Net Revenues	**$5,112**

The TPP for the two year rate period is greater than 95%.

Table 1.2 shows planned transmission repayments to the U.S. Treasury during the rate test period.

Table 1.2

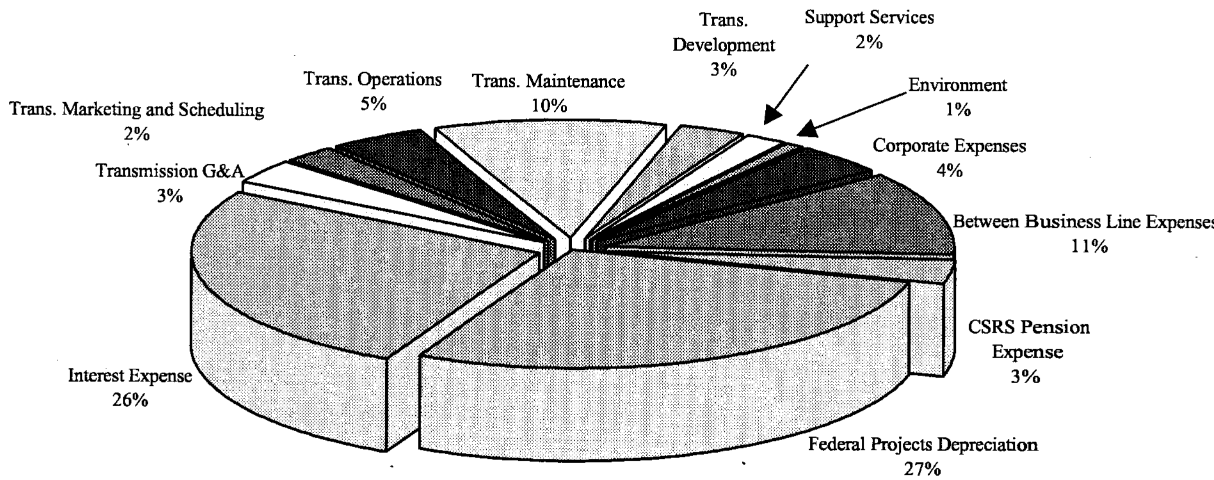
PLANNED REPAYMENTS TO U.S. TREASURY
FYs 2002 – 2003 TRANSMISSION REPAYMENT STUDIES
($000s)

Fiscal Year	**Annual Amortization**
2002	$131,517
2003	$142,791
Total	$274,308

The transmission operating expenses for FY 2002-2003 included in this proposed revenue requirement appear in Figure 1.2.

FIGURE 1.2

Composition of Transmission Operating & Interest Expenses FY 2002-2003 Average



($ in millions)

	FY 2002	FY 2003	Average	
Transmission G&A	$ 22.2	$ 23.8	$ 23.0	3%
Transmission Marketing and Scheduling	$ 15.2	$ 15.7	$ 15.5	2%
Transmission System Operations	$ 31.0	$ 32.1	$ 31.6	5%
Transmission System Maintenance	$ 71.3	$ 73.4	$ 72.4	11%
Transmission System Development	$ 21.4	$ 21.6	$ 21.5	3%
Support Services	$ 11.9	$ 12.2	$ 12.1	2%
Environment	$ 5.1	$ 5.3	$ 5.2	1%
Corporate Expenses	$ 30.0	$ 28.1	$ 29.1	4%
Between Business Line Expenses	$ 77.3	$ 77.3	$ 77.3	11%
CSRS Pension Expense	$ 27.6	$ 17.6	$ 22.6	3%
Federal Projects Depreciation	$ 181.7	$ 194.0	$ 187.9	28%
Interest Expense	$ 176.3	$ 178.1	$ 177.2	26%
Total Transmission Expenses	**$ 671.0**	**$ 679.2**	**$ 675.1**	**100%**

1.2 Public Involvement Processes

BPA has been the focus of and/or has conducted several regional public processes that have had significant impacts on its methods and costs of doing business. In 1998, BPA worked with the Northwest Power Planning Council (NWPPC) in the Cost Review of the Federal Columbia River

Power System. BPA outlined its plans to implement the Cost Review recommendations in a subsequent public process entitled Issues '98. Even though the Issues '98 forum primarily focused on BPA's power costs, BPA committed to ensuring that its transmission costs would be as low as possible consistent with sound business practices.

Concurrent with, but independent of preparing this rate proposal, BPA also conducted a public process to ask customers and constituents for their thoughts about planned capital spending and the expenses associated with supporting a reliable and safe transmission system. These meetings, held throughout the region between November 1999 and February 2000, specifically explored customer and constituent views on:

- Maintaining system reliability commensurate with national and regional guidelines;
- Meeting local load growth;
- Improving areas where the transmission system is constrained;
- Upgrading communications systems with fiber optics;
- Replacing aging equipment; and
- Succession planning for the aging workforce, specifically in critical positions.

The customer and constituent views expressed during this public process were summarized and addressed in letter by the Administrator issued on June 28, 2000, entitled "Program Level Expense and Capital Spending – Fiscal Years 2002 and 2003 Close-out of the Program Level Public Process." This letter is included in Appendix B of the Revenue Requirement Study, TR-02-FS-BPA-01. The Administrator's decisions, as outlined in this close-out letter and accompanying appendix, are reflected in the revenue requirements, including repayment studies, in this rate proposal. *See* Chapter 2 of this Study for a chronology of the spending level development process.

2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

2.1 Development Process for Spending Levels

Development of spending levels reflected in these revenue requirements began with the Comprehensive Review of the Northwest Energy Systems (Comprehensive Review), which the governors of Idaho, Montana, Oregon, and Washington initiated in 1996 to seize opportunities and moderate risks presented by the transition of the region's transmission and power systems to a more competitive market. The Comprehensive Review recognized that this transition raised fundamental issues for transmission, such as ensuring reliable service, minimizing cost shifts and not increasing risk of repayment of the Federal investment to Treasury.

A theme of the Comprehensive Review was that BPA and the other entities of the Federal Columbia River Power System (FCRPS) must effectively manage and control costs. Specifically, the Comprehensive Review recommended that BPA promote the broadest possible bulk power market competition through (1) functional separation of BPA's transmission operations from its power marketing function, (2) providing open access transmission service without increasing repayment risk for the U.S. Treasury and (3) retaining the substantial long-term benefits of the FCRPS for the Northwest. In addition, the Comprehensive Review recognized that business line separation and open access transmission service consistent with FERC directives would bring increased cost pressures on transmission as it became responsible for some generation costs.

An outgrowth of the Comprehensive Review was the Cost Review of the FCRPS (Cost Review), referred to in Chapter 1 of this Study. In September 1997, BPA and the NWPPC jointly launched a review of FCRPS costs. The objectives of the Cost Review were to ensure that

BPA's long-term power and transmission costs would be as low as possible, consistent with sound business practices. The intent of the Cost Review relating to transmission issues was to:

1. Give confidence to BPA customers, tribes, and constituents that FCRPS costs would be managed effectively;
2. Minimize, if not avoid, transition (stranded) costs; and
3. Ensure that obligations to the U.S. Treasury and third-party bondholders would remain at least as secure as they were in 1998.

The Cost Review drew on the expertise of five executives with experience in managing large organizations undergoing competitive transitions. A draft of the panel's recommendations was submitted to a month-long regional public comment process, which included two broadly attended public meetings. In addition, there were briefings of other groups throughout the region, including tribal, public power and environmental interests. The draft recommendations were modified to take into account comments received, and then submitted to the Administrator, the region's Governors, the Northwest Congressional delegation, and the House and Senate Committees on Appropriations in March 1998.

In June 1998, BPA began a public involvement process entitled Issues '98. Issues '98 was designed to provide the region an overview and context for major policy issues surrounding BPA's future, including cost management and other Cost Review recommendations, and an opportunity to comment on the proposals. As with the Cost Review, Issues '98 focused primarily on Bonneville's power business line. In addition to taking written comment, three public meetings where held within the region to provide an opportunity for the public to participate. At the conclusion of the Issues '98 process, BPA completed and released the "Cost Review Implementation Plan." This document, published in October 1998, summarized the thirteen recommendations of the Cost Review, the implementation plan, and relevant customer comments.

The transmission-related recommendations in the Cost Review and affirmed in Issues '98 were made to specific cost baselines that already included significant cost control initiatives, including:

- Holding the TBL O&M costs constant in nominal dollars;
- Reducing TBL and Corporate Federal and contractor FTE levels and administrative costs;
- Constraining Federal investments to levels commensurate with availability of low-cost sources of capital; and
- Redesigning information technology and accounting/financial reporting system and services to be more responsive and less costly.

For transmission, the Cost Review recommended that BPA: enhance transmission cost management through improved capital asset management; reduce administrative and internal services costs; and adjust and correct the functionalization and allocation of costs in accordance with FPA conformance. For the 2002-06 period transmission cost reductions were expected to be $1.5 million annual average through improved efficiencies, with an additional estimate of at least a $30 million cost shift from power to transmission for Federal Power Act conformance and reductions to general and administrative services costs provided by Corporate and Shared Services.

In the 1996 Rate Case, BPA originally proposed a 36 percent transmission rate increase to recover forecasted costs over the five-year rate period (FY1997-2001). As part of the global settlement of power and transmission issues, the transmission rate increase was limited to 13.5 percent for the five-year rate period. While that decision created no precedent, it had a significant impact upon BPA's transmission expense and capital programs for the 1996-2001 rate period, and was the driver in the Cost Review and Issues '98 targets of holding transmission expenses flat for FY 1998 through 2001. In an effort to implement these targets and stay within the cost levels outlined in the 1996 rate case for the FY1997-2001 rate period, the TBL implemented cost cuts, adopted efficiencies in its transmission operation and maintenance programs and deferred transmission system improvements. However, a number of factors have caused actual and forecasted expenses for this proposal to be greater than levels forecasted in the 1996 rate case, Cost Review, and Issues '98. These factors include:

- Business line separation costs including the implementation of functional separation and separate systems for billing, scheduling, contracting and marketing.
- TBL's obligation to fully fund payments to the Civil Services Retirement System (and additional $27.6 million in FY02 and $17.6 million in FY03), and negotiated wage and benefits increases for 50 percent of all TBL positions covered by the Columbia Power Trades Council (CPTC) Agreement;
- Planning for replacements of an aging TBL workforce, one-half of which is eligible to retire within five (5) years; and obtaining personnel to address higher and more complex uses of the system;
- As a result of functional unbundling, the costs of generation inputs for ancillary services are now the responsibility of the TBL. Portions of these costs, which are now higher than the Cost Review estimates, were previously bundled in the power rates; and
- Inflation on materials and services, and wage and benefits for General Schedule employees.

See Table 2.1.

Table 2.1

Comparison of 1997-2001 Averages for 1996 Final Rate Proposal, Issues '98, Current Estimates (1997-1999 Actuals plus 2000 –2001 Forecast), and 2002-2003 Final Proposal

(Average Annual $ in millions)

Expenses	1996 Rate Case (1997-2001)1/	Issues '98 (FY1997-2001)	Current Actuals and Estimates (FY1997-01) 2/	Final Proposal Revenue Requirement (FY2002-2003)	Cost Pressures impacting the Initial Proposal Revenue Requirement 3/
G&A	$3.4	$13.4	$18.2	$23.0	Due to an oversight, G&A was understated $12 million in 1996 Rate Case
Marketing and Scheduling	$7.2	$13.6	$13.3	$15.5	Scheduling, billing, and marketing increases are due, ir large part, to separation.
System Operations	$25.4	$25.1	$27.1	$31.6	Increase due to stability reserves, WSCC requirements and succession planing.
System Maintenance	$58.5	$59.6	$64.2	$72.4	Personnel Compensation
System Development	$15.3	$10.7	$12.4	$21.5	GTA leases and new leases.
Environment	$8.4	$7.7	$5.5	$5.2	
Support Services	$3.7	$8.9	$9.9	$12.1	4/
Corporate & Shared Services	$37.0	$32.4	$34.5	$29.1	Consistent with Cost Review recommendation to reduce agency administrative and support services costs.
CSRS Expense	$0.0	$1.2	$2.0	$22.6	BPA agreement with OMB to repay unrecovered Civil Service Retirement Costs
Total System Operation & Maintenance	**$158.9**	**$172.6**	**$187.1**	**$233.0**	
Between Business Line Expenses	$40.8	$15.2	$33.7	$77.3	Increased costs for Generation Inputs for reserve services.
Total (excluding depreciation and interest)	**$199.7**	**$187.8**	**$220.8**	**$310.0** 5/	

1/ Adjusted for comparison purposes because the Final 1996 rate proposal did not anticipate impact of cost shifts for separation. In 1996 rate proposal, wheeling costs were functionalized to transmission, and "between business line expenses" were the portion of the transmission costs included in bundled power.
2/ Includes actual costs for 1997 through 1999 and forecast costs for 2000 - 2001(March, 2000).
3/ General increases in wages and benefits ($12 million) and inflation ($6 million) were significant cost pressures and are reflected in several cost categories.
4/ Increases in Shared Services due to reclassification of costs from System Operations and Maintenance
5/ Does not add due to rounding

BPA determines program spending levels separate from the rate process. BPA conducted numerous regional workshops, beginning in November 1999, to ask for customer input in a public forum entitled "Reliability and the Future of Transmission Costs." The process specifically solicited public comment on BPA's proposed FY 2002-2003 spending levels for transmission system operations. This forum also included a discussion with customers and constituents of capital spending levels and planned transmission system improvement, upgrade and reinforcement projects.

Specifically, TBL identified capital investments that are necessary to:

- meet increased wholesale transmission transactions, reliably serve load growth, provide reactive needs and new generation reinforcements and system replacements, alleviate constrained paths, and respond to changes in reliability criteria;
- invest in technology and personnel to address significantly higher and more complex uses of BPA's transmission system;
- meet the requirements for Business line separation including the implementation of separate systems for billing scheduling, contracting and marketing functions; and
- replace aging equipment and maintain the system in a safe, reliable, environmentally responsible, and cost-effective manner.

Notices of the workshops were widely distributed to TBL's customers and interested parties and were published on BPA's OASIS. Workshop participants were clearly informed that the outcome of this public process would be the basis for the revenue requirements used to set rates. Five public workshops were held in November 1999 and two in February 2000. Substantial oral and written comments were provided by workshop participants to clarify and examine BPA's planned transmission capital spending and expenses. Written comments on TBL's planned capital spending and expenses were formally accepted through February 25, 2000.

The customer and constituent views expressed during this public process were summarized and addressed in letter by the Administrator issued on June 28, 2000, entitled "Program Level Expense and Capital Spending – Fiscal Years 2002 and 2003 Close-out of the Program Level Public Process." The Administrator's decisions, as outlined in this close-out letter and accompanying appendix, have been reflected in the revenue requirements, including repayment studies, in this rate proposal. This letter is included in Appendix B of the Revenue Requirement Study, TR-02-FS-BPA-01.

In addition to reflecting decisions made in the program level public process, this rate proposal includes the final cost estimates that were decided in the recently concluded 2002 wholesale power rate case. The scope of the separate rate proceeding for wholesale power rates included:

- a methodology for functionalizing corporate overhead costs, and generation and transmission costs;
- unit costs for generation inputs for operating reserves and regulation ancillary services;
- the generation input cost for reactive supply and voltage control from generation resources;
- the power costs of station service and remedial action schemes; and
- the allocation of generation integration and generator step-up transformers to the power business line

BPA's 2002 power rate case proposal also included a treatment of GTA costs and their replacement for the delivery of both Federal and non-Federal power, and BPA-PBL's support of the utility delivery charge.

2.2 Financial Risk and Mitigation

BPA adopted a long-term policy in its 1993 Final Rate Proposal which called for setting rates that build and maintain financial reserves sufficient for the agency to achieve a 95 percent probability of meeting U.S. Treasury payments in full and on time for each two-year rate period. *See* 1993 Final Rate Proposal, Administrator's Record of Decision, WP-93-A-02 at page 72. For further discussion of the TPP standard, see the Generation 2002 Final Power Rate Proposal Revenue Requirement Study, WP-02-FS-BPA-02, Chapter 2, Section 2.2, p. 18; and the 2002

Final Power Rate Proposal, Administrator's Record of Decision, WP-02-A-02 at pages 7-7 to 7-16.

Since 1993, the Comprehensive Review (discussed in Section 2.1) highlighted the need for a high Treasury payment probability. The Comprehensive Review recommendations were developed with several goals in mind, one of these being to "ensure repayment of the debt to the U.S. Treasury with a greater probability than currently exists . . ." At the time of the Comprehensive Review, BPA's 1996 rates assumed an 80 percent probability of meeting Treasury payment in full and on time for the 5-year period.

In this rate proposal, BPA has, for the first time, analyzed its transmission risks and proposed risk mitigation tools designed to achieve the 95 percent TPP standard for the transmission function. A probability at this level satisfies the objectives of the 1993 decision and is in keeping with the Comprehensive Review recommendation of an improved probability of full repayment to the Treasury.

To achieve this Treasury payment probability (TPP), the following risk mitigation "tools" are considered in the rate proposal:

1. Starting reserves: Starting financial reserves include cash in the BPA Fund and the deferred borrowing balance attributed to the transmission function. The risk-adjusted value for starting reserves is projected to total $45.2 million at the beginning of FY 2002.
2. Planned Net Revenues for Risk (PNRR). PNRR is a component of the revenue requirement that is added to annual expenses. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short run volatility in costs and revenues and achieve the TPP goal.
3. Two Year Rate Period. BPA is proposing to adopt 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. The impact of a two year rate period is

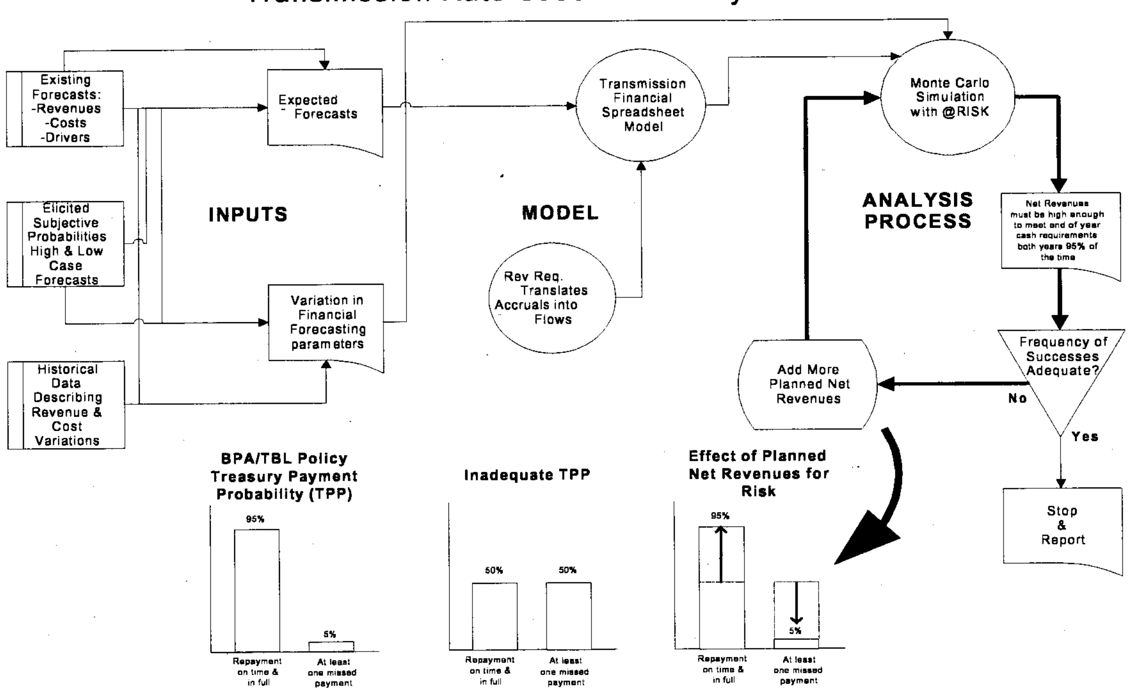
to limit the effects of uncertainty which must be mitigated by other risk mitigation tools to the period of time from the date of the final proposal through FY 2003. Longer run risks are mitigated by the ability to change rate levels.

Transmission Risk Analysis

To quantify the effects of risk on the finances of BPA's transmission function, BPA analyzes the effects of uncertainty in costs and revenues on transmission cash flows using a Monte Carlo simulation method. *See* Figure 2.1. 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 cash reserves for the transmission function, after Treasury payments are made, are sufficient to cover the transmission function's working capital requirement of $20 million. The working capital threshold is based on the monthly net cash flow patterns and requirements for the transmission function.

Figure 2.1

Transmission Rate Case Risk Analysis -



The risk analysis is used in an iterative process with the Revenue Requirement Study and the Transmission Rate Study (TRS). The risk analysis uses data developed in both of these studies and contributes data to those studies in the form of forecasted cash reserves at the beginning of the FY 2002 to FY2003 rate period and PNRR. Initial input values for point estimates of costs and revenues come from the Revenue Requirements Study and the TRS and, when combined with inputs describing uncertainty in costs and revenues, provide the basis for the initial estimate of PNRR. The PNRR is, in turn, provided as an expense input to the Revenue Requirements Study and the TRS, changing the transmission revenue requirement and transmission rates. This iterative analysis process is continued until successive estimates of PNRR converge.

The risk analysis covers the period FY1999 through FY 2003. This time frame is used to permit analyzing the change in revenues, costs, and accrual to cash adjustments that are expected to occur between the development of the final rate proposal and the end of the rate period. The advantage to this approach is that cash reserves by the end of the FY 1996-FY 2001 rate period may be directly estimated, including the impact of uncertainty, thus helping define the starting conditions for the FY 2002-FY 2003 rate period.

Transmission Risk Analysis Processor Spreadsheet

The foundation of the risk analysis is a transmission financial spreadsheet model, called the Transmission Risk Analysis Processor (TRAP). *See* Revenue Requirements Study Documentation, at TR-02-FS-BPA-01A. This model was developed to estimate the effects of risk and risk mitigation on end-of-year cash reserves and likelihood of successful Treasury payment during the rate period. Cash reserve levels at the end of the fiscal year determine whether BPA is able to meet its Treasury payment obligation. End-of year cash balances during the rate period are, therefore, the main outcome of the model. The TRAP contains individual work sheets including: an input matrix of revenues and costs, an income statement, a cash flow statement, and individual work sheets for variables specified with uncertainty in the model. Parameters for the probability distributions were developed from historical data and analysis of risk factors.

2.3 Capital Funding

BPA transmission capital outlay projections for this proposal are $488,236 thousand for the FY 2002-2003 rate period. These investments include:

- transmission programs ($447.4 million);
- environmental program ($18.3 million);
- investments in ADP and other capital equipment ($22.6 million).

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

Bonds Issued to the Treasury

Bonds issued to Treasury will be the source of capital used to finance FY 2002 - 2003 BPA 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 chapter 6 of the Documentation for Revenue Requirement Study, TR-02-FS-BPA-01A.

Federal Appropriations

This Study includes the original capital investments in the Federal transmission system that were financed by Federal appropriations prior to BPA self-financing. No new investments in the rate period are forecast to be funded by appropriations. "The Bonneville Appropriations Refinancing

Act" (the Refinancing Act) was enacted in April 1996. This Refinancing Act reset the unpaid principal of FCRPS appropriations and reassigned interest rates. New principal amounts were established at the beginning of FY 1997, at the present value of the principal and annual interest payments BPA would make to the Treasury for these obligations in the absence of the Refinancing Act, plus $100 million. Before implementation of the Refinancing Act there were $1,545.7 million BPA appropriations outstanding. After the implementation of the Refinancing Act, $1,075.4 million in BPA Appropriations were outstanding. The Refinancing Act restricted prepayment of the new principal to $100 million in the FY 1996-2000 period. Other repayment terms were unaffected. The repayment studies in the Study fully incorporate implementation of the Refinancing Act. For further discussion of the Refinancing Act, see BPA's 2002 Final Power Rate Proposal Revenue Requirement Study, WP-02-FS-BPA-02, Chapter 2, Section 2.3, p. 26 and Chapter 8 of the Documentation for the Generation Revenue Requirement Study, WP-02-FS-BPA-02A.

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 the 1996 rate case, repayment studies for transmission were run with 45 year repayment periods for each rate test year. For this study, the repayment period horizon has been set at 35 years. This shorter study horizon reflects the fact that the outstanding appropriations and bonds in the transmission system are fully repaid within this period. It also more closely matches the terms of the shorter maturity bonds being issued, and reflects the estimated average service life of plant which is now 40 years. Shortening the horizon any further would result in some obligations not being paid by their due dates.

The Revenue Requirement Study includes the results of transmission repayment studies for each of the two years in the rate test period, FY 2002 – 2003. In conducting the repayment studies, BPA includes currently outstanding and projected transmission repayment obligations on appropriations and on bonds issued to Treasury. Funding for replacements projected during the repayment period are also included in the repayment study, consistent with the requirements of RA 6120.2.

Historical appropriations are scheduled to be repaid within the expected useful life of the associated facility (currently 40 years), or 50 years, whichever is less. Actual bonds issued by BPA to the Treasury may be for terms ranging from 3 to 45 years, taking into account the estimated average service lives for 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. Many bonds are issued with a provision that allows the bond to be called after a certain time, typically five years. Bonds may also be issued with no early call provision. Early retirement of eligible bonds requires that BPA pay a bond premium to the Treasury. The premium that is paid on any Federal bond is considered to be due when the Federal bond is due. 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 and repaid within the provisions of each bond agreement with the Treasury.

Based on these parameters, the repayment study establishes a schedule of planned amortization payments and resulting gross 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 and repayment program tables is included in this Study at Appendix A; and in Chapter 5 of the Documentation for Revenue Requirement Study, TR-02-FS-BPA-01A. *See* Chapter 5 of this Study, for an explanation of repayment policies and requirements.

4. FY 2002 TRANSMISSION REVENUE REQUIREMENTS

This chapter explains the cost accounting formats used to develop revenue requirements for FYs 2002 and 2003. Section 4.1.1 provides a line-by-line description of the Revenue Requirement Income Statement and Section 4.1.2 provides a line-by-line description of the Revenue Requirement Statement of Cash Flows.

4.1 Revenue Requirement Format

For each year of a rate test period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, 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 4.1A) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 5), Net Interest Expense (Line 14), Minimum Required Net Revenues (Line 16), and Planned Net Revenues for Risk (Line 17). The sum of these four major components is the Total Revenue Requirement (Line 19).

The Minimum Required Net Revenues (Line 16) result from an analysis of the Statement of Cash Flow (Table 4.1B). 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 Flow analyzes annual cash inflows and outflows. Cash Provided by Current Operations (Line 8), driven by the Non-cash Expenses shown in Lines 4, 5 and 6, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 12) and Cash From Treasury Borrowing (Line 17). If cash provided by Current Operations are not sufficient, Minimum Required Net Revenues must be included in revenue requirements to accommodate the shortfall, yielding at least a zero annual Increase in Cash (Line 18). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) is then incorporated in the Income Statement (Line 16).

4.1.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 4.1A). The documentation for the Revenue Requirement Study, TR-02-FS-BPA-01A, provides additional information on the development and use of the data contained in the tables.

Operation & Maintenance (Line 2)

Operation & Maintenance represents FCRTS O&M expenses incurred by BPA. Specific BPA O&M expenses include transmission scheduling, transmission marketing, transmission system operations, transmission system maintenance, transmission system development, environment, non-Federal transmission arrangements, leases, TBL general and administrative, TBL support services, Civil Service Retirement System pension expense, and corporate administrative and support services. (*See* Chapter 3, Documentation, TR-02-FS-BPA-01A)

Inter-Business Line Expenses (Line 3)

Inter-business line expenses, resulting from functional separation and ancillary services products, include the generation inputs to ancillary services from the PBL, station service and remedial action schemes, and the cost of COE and BOR transmission facilities serving the network and utility delivery segments. (*See* Chapter 3, Documentation, TR-02-FS-BPA-01A).

Federal Projects Depreciation (Line 4)

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. (*See* Chapter 4, Documentation, TR-02-FS-BPA-01A).

Total Operating Expenses (Line 5)

Total Operating Expenses is the sum of the above expenses (Lines 2 through 4).

Interest on Appropriated Funds (Line 8)

Interest on Appropriated Funds consists of interest on the pre-self financing BPA appropriations as determined in the transmission repayment studies. (*See* Chapter 3 Documentation, TR-02-FS-BPA-01A).

Interest on Long-Term Debt (Line 9)

Interest on long-term debt includes interest on bonds that BPA issues to the U.S. 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 premiums for bonds projected to be amortized are included in this line. 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 the Appendix. (*See* Chapter 3, Documentation, TR-02-FS-BPA-01A).

Interest Credit on Cash Reserves (Line 10)

Interest income is also computed on the projected year-end cash balances in the BPA fund attributable to the transmission function that carry over into the next year. It is credited against bond interest. (*See* Chapter 5, Documentation, TR-02-FS-BPA-01A).

Amortization of Capitalized Bond Premiums (Line 11)

When a bond issued to the U.S. Treasury is refinanced, any call premium resulting from early retirement of the original bond is capitalized and included in the principal of the new bond. The capitalized call premium is then amortized over the term of the new bond. The annual amortization is a non-cash component of interest expense. (*See* Chapter 3, Documentation, TR-02-FS-BPA-01A).

Capitalization Adjustment (Line 12)

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 as a result of the refinancing million. 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. (*See* Chapter 3, Documentation, TR-02-FS-BPA-01A).

Allowance for Funds Used During Construction (AFUDC) (Line 13)

AFUDC is a credit against interest on long-term debt (Line 9). 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. 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.

Net Interest Expense (Line 14)

Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 8), Interest on Long-Term Debt (Line 9), Interest Credit on Cash Reserves (Line 10), Amortization of Capitalized Bond Premiums (Line 11), Capitalization Adjustment (Line 12), and AFUDC (Line 13).

Total Expenses (Line 15)

Total Expenses are the sum of Total Operating Expenses (Line 5) and Net Interest Expense (Line 14).

Minimum Required Net Revenues (Line 16)

Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 4.1B), 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 below.

Planned Net Revenues for Risk (Line 17)

Planned Net Revenues for Risk are 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 reserves in FY 2002 and the cash flow from non-cash expenses exceeding cash payments are sufficient to mitigate risk in FYs 2002 and 2003.

Total Planned Net Revenues (Line 18)

Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 16) and Planned Net Revenues for Risk (Line 17).

Total Revenue Requirement (Line 19)

Total Revenue Requirement is the sum of Total Expenses (Line 15) and Total Planned Net Revenues (Line 18).

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 4.1B). Documentation, TR-02-FS-BPA-01A, provides additional information related to the use and development of the data contained in the table.

Minimum Required Net Revenues (Line 2)

Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required Net Revenues may be necessary so that the cash provided from operations will be sufficient to cover the planned amortization payments (the difference between Lines 12 and 17) without causing the Annual Increase (Decrease) in Cash (Line 18) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 16).

Federal Projects Depreciation (Line 4)

Depreciation is from the Income Statement (Table 4.1A, Line 4). It is included in computing Cash Provided By Operations (Line 8) because it is a non-cash expense of the FCRTS.

Amortization of Capitalized Bond Premiums (Line 5)

Amortization of Capitalized Bond Premiums, from the Income Statement (Table 4.1A, Line 11), is a non-cash expense.

Capitalization Adjustment (Line 6)

The Capitalization Adjustment, from the Income Statement (Table 4.1A, Line 12), is a non-cash (contra) expense. (See Chapter 3, Documentation, TR-02-FS-BPA-01A).

Accrual Revenues (AC Intertie/Fiber) (Line 7)

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 BPA's transmission system (straight-line over 45 years). Similarly, some of the 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.

Cash Provided By Current Operations (Line 8)

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

Investment in Utility Plant (Line 11)

Investment in Utility Plant represents the annual increase in capital spending related to additions and replacements to plant-in-service for BPA. (See Chapter 7, Documentation, TR-02-FS-BPA-01A).

Cash Used for Capital Investments (Line 12)

Cash Used for Capital Investments is Line 11.

Increase in Long-Term Debt (Line 14)

Increase in Long-Term Debt reflects the new bonds issued by BPA to the U.S. Treasury to fund transmission and capital equipment programs. Also included in this amount may be any notes issued to the U.S. Treasury. (See Chapter 7, Documentation, TR-02-FS-BPA-01A).

Repayment of Long-Term Debt (Line 15)

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 Chapter 3, Documentation, TR-02-FS-BPA-01A).

Repayment of Capital Appropriations (Line 16)

Repayment of Capital Appropriations represents projected amortization of outstanding BPA appropriations (pre self-financing) as determined in the repayment studies. (See Chapter 3, Documentation, TR-02-FS-BPA-01A).

Cash From Treasury Borrowing and Appropriations (Line 17)

Cash From Treasury Borrowing and Appropriations is the sum of Lines 14 through 16. 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 18)

Annual Increase (Decrease) in Cash, the sum of Lines 8, 12, and 17, reflects the annual net cash flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues would be insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease. See discussion above of Minimum Required Net Revenues (Line 2).

Planned Net Revenues For Risk (Line 19)

Planned Net Revenues For Risk reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 4.1A, Line 17.)

Total Annual Increase (Decrease) in Cash (Line 20)

Total Annual Increase (Decrease) in Cash, the sum of Lines 18 and 19, is the total annual cash that is projected to be available to add to BPA's cash reserves.

4.2 Current Revenue Test

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

For the rate test period, the demonstration of the inadequacy of current rates is shown on Tables 4.2A and 4.2B. Table 4.2A is a pro forma income statement for each year. Table 4.2B, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 4.2A (Line 17) for making the planned annual amortization payments and achieving the Administrator's financial objectives. This is demonstrated by the Total Annual Increase (Decrease) in Cash (Line 18). As explained in section 2 of the Appendix, the annual cash flow (Line 18) 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 substantially insufficient to satisfy cost recovery requirements in the rate period.

Table 4.3 shows the inadequacy of current rates to satisfy cost recovery requirements over the 35-year repayment period. The focal point of these tables is the Net Position (Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the allowable time. As shown in Column K, the Net Position results are negative for each year of the rate approval period and in each year of the repayment period.

4.3 Revised Revenue Test

Consistent with RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements as well as the 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 Transmission Rate Study, Chapter 2, TR-02-FS-BPA-03). The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery requirements for the rate approval period of FYs 2002 and 2003.

For the rate test period, the demonstration of the adequacy of proposed rates is shown on Tables 4.4A and 4.4B. Table 4.4A presents pro forma income statements for each year.

Table 4.4B, Statements of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 4.4A (Line 17) for making the planned annual amortization payments and achieving the Administrator's financial objectives. This is demonstrated by the Total Annual Increase (Decrease) in Cash (Line 18). As explained in section 2 of the Appendix, the annual cash flow (Line 18) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements.

4.4 Repayment Test at Proposed Rates

Table 4.5 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 4.4A and 4.4B) and separate accounting analyses. The focal point of these tables is the Net Position (Column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRPS within the allowable time. As shown in Column K, the resulting Net Position is greater than zero for each year of the rate approval period and in each year of the repayment period.

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

TABLE 4.1A
TRANSMISSION REVENUE REQUIREMENT
INCOME STATEMENT
($thousands)

		A FY 2002	B FY 2003
1	OPERATING EXPENSES		
2	OPERATION AND MAINTENANCE	235,686	229,810
3	INTER-BUSINESS LINE EXPENSES	77,320	77,303
4	FEDERAL PROJECTS DEPRECIATION	181,734	194,009
5	TOTAL OPERATING EXPENSES	494,740	501,122
6	INTEREST EXPENSE		
7	INTEREST ON FEDERAL INVESTMENT -		
8	ON APPROPRIATED FUNDS	66,904	65,280
9	ON LONG-TERM DEBT	134,812	140,940
10	INTEREST CREDIT ON CASH RESERVES	(5,862)	(7,835)
11	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,220	3,220
12	CAPITALIZATION ADJUSTMENT	(19,618)	(20,174)
13	AFUDC	(5,040)	(5,225)
14	NET INTEREST EXPENSE	174,416	176,206
15	TOTAL EXPENSES	669,156	677,328
16	MINIMUM REQUIRED NET REVENUES 1/	0	0
17	PLANNED NET REVENUES FOR RISK	0	0
18	TOTAL PLANNED NET REVENUES	0	0
19	**TOTAL REVENUE REQUIREMENT**	**669,156**	**677,328**

1/ SEE NOTE ON CASH FLOW TABLE.

TABLE 4.1B
TRANSMISSION REVENUE REQUIREMENT
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2002	B FY 2003
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUES 1/	0	0
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	181,734	194,009
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,220	3,220
6	CAPITALIZATION ADJUSTMENT	(19,618)	(20,174)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(4,031)	(4,031)
8	CASH PROVIDED BY CURRENT OPERATIONS	161,305	173,024
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(252,300)	(248,416)
12	CASH USED FOR CAPITAL INVESTMENTS	(252,300)	(248,416)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	252,300	248,416
15	REPAYMENT OF LONG-TERM DEBT	(107,848)	(116,809)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(23,913)	(26,247)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	120,539	105,360
18	ANNUAL INCREASE (DECREASE) IN CASH	29,544	29,968
19	PLANNED NET REVENUES FOR RISK	0	0
20	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	29,544	29,968

1/ Line 18 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

TABLE 4.2A
CURRENT REVENUE TEST
INCOME STATEMENT
($thousands)

		A	B
		FY 2002	**FY 2003**
1	REVENUES FROM CURRENT RATES	504,061	515,058
2	OPERATING EXPENSES		
3	OPERATION AND MAINTENANCE	238,071	232,195
4	INTER-BUSINESS LINE EXPENSES	84,276	84,243
5	FEDERAL PROJECTS DEPRECIATION	182,694	195,358
6	TOTAL OPERATING EXPENSES	505,041	511,796
7	INTEREST EXPENSE		
8	INTEREST ON FEDERAL INVESTMENT -		
9	ON APPROPRIATED FUNDS	66,904	65,280
10	ON LONG-TERM DEBT	143,126	143,418
11	INTEREST CREDIT ON CASH RESERVES		
12	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,220	3,220
13	CAPITALIZATION ADJUSTMENT	(19,618)	(20,174)
14	AFUDC	(5,040)	(5,225)
15	NET INTEREST EXPENSE	188,592	186,519
16	TOTAL EXPENSES	693,633	698,315
17	NET REVENUES	(189,572)	(183,257)

TABLE 4.2B
TRANSMISSION REVENUE REQUIREMENT
CURRENT REVENUE TEST
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2002	B FY 2003
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	(189,572)	(183,257)
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	182,694	195,358
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,220	3,220
6	CAPITALIZATION ADJUSTMENT	(19,618)	(20,174)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(4,031)	(4,031)
8	CASH PROVIDED BY CURRENT OPERATIONS	(27,307)	(8,884)
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(252,300)	(248,416)
12	CASH USED FOR CAPITAL INVESTMENTS	(252,300)	(248,416)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	252,300	248,416
15	REPAYMENT OF LONG-TERM DEBT	(124,226)	(124,233)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(23,913)	(26,247)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	104,161	97,936
18	ANNUAL INCREASE (DECREASE) IN CASH	(175,446)	(159,364)

TABLE 4.3
FEDERAL COLUMBIA RIVER TRANSMISSION SYSTEM
TRANSMISSION REVENUES FROM CURRENT RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

	A	B	C	D	E	F	G	H	I	J	K
YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY TABLE 12B)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
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	125,961	145,411 /5/6	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	124,457	114,383 /7	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	125,130	129,855 /8	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	147,176	135,259 /9	139,784		(4,525)
COST EVALUATION PERIOD											
2000	554,132	264,064		153,955	163,035	(26,922)	153,955	108,322 /10	114,587		(6,265)
2001	564,166	270,138		153,955	172,193	(32,120)	153,955	158,819 /11	59,060		99,759
RATE APPROVAL PERIOD											
2002	528,665	313,006		181,734	188,592	(154,667)	161,305	6,638	131,517		(124,879)
2003	539,369	307,113		194,009	186,519	(148,272)	173,024	24,752	142,791		(118,039)

	A	B	C	D	E	F	G	H	I	J	K
REPAYMENT PERIOD	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY TABLE 12B)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
2004	539,369	307,113	(1,041)	194,009	190,916	(151,628)	173,024	21,396	140,785		(119,389)
2005	539,369	307,113	(1,073)	194,009	189,408	(150,088)	173,024	22,936	142,325		(119,389)
2006	539,369	307,113	(1,104)	194,009	191,781	(152,430)	173,024	20,594	139,983		(119,389)
2007	539,369	307,113	(1,134)	194,009	187,988	(148,607)	173,024	24,417	143,806		(119,389)
2008	539,369	307,113	(1,164)	194,009	188,237	(148,826)	173,024	24,198	143,587		(119,389)
2009	539,369	307,113	(1,193)	194,009	191,198	(151,758)	173,024	21,266	140,655		(119,389)
2010	539,369	307,113	(1,221)	194,009	189,641	(150,173)	173,024	22,851	142,240		(119,389)
2011	539,369	307,113	(1,249)	194,009	187,865	(148,369)	173,024	24,655	144,044		(119,389)
2012	539,369	307,113	(1,277)	194,009	187,959	(148,435)	173,024	24,589	143,978		(119,389)
2013	539,369	307,113	(1,303)	194,009	187,896	(148,346)	173,024	24,678	144,067		(119,389)
2014	539,369	307,113	(1,329)	194,009	187,886	(148,310)	173,024	24,714	144,103		(119,389)
2015	539,369	307,113	(1,355)	194,009	188,605	(149,003)	173,024	24,021	143,410		(119,389)
2016	539,369	307,113	(1,380)	194,009	191,962	(152,335)	173,024	20,689	140,078		(119,389)
2017	539,369	307,113	(1,404)	194,009	194,569	(154,918)	173,024	18,106	137,495		(119,389)
2018	539,369	307,113	(1,428)	194,009	195,238	(155,563)	173,024	17,461	136,850		(119,389)
2019	539,369	307,113	(1,451)	194,009	196,301	(156,603)	173,024	16,421	135,810		(119,389)
2020	539,369	307,113	(1,474)	194,009	196,403	(156,682)	173,024	16,342	135,731		(119,389)
2021	539,369	307,113	(1,496)	194,009	199,469	(159,726)	173,024	13,298	132,687		(119,389)
2022	539,369	307,113	(1,517)	194,009	201,068	(161,304)	173,024	11,720	131,109		(119,389)
2023	539,369	307,113	(1,538)	194,009	200,314	(160,529)	173,024	12,495	131,884		(119,389)
2024	539,369	307,113	(1,557)	194,009	205,691	(165,887)	173,024	7,137	126,526		(119,389)
2025	539,369	307,113	(1,576)	194,009	208,126	(168,303)	173,024	4,721	124,110		(119,389)
2026	539,369	307,113	(1,594)	194,009	214,147	(174,306)	173,024	(1,282)	118,107		(119,389)
2027	539,369	307,113	(1,613)	194,009	218,554	(178,694)	173,024	(5,670)	113,719		(119,389)
2028	539,369	307,113	(1,629)	194,009	219,875	(179,999)	173,024	(6,975)	112,414		(119,389)
2029	539,369	307,113	(1,644)	194,009	228,661	(188,770)	173,024	(15,746)	103,643		(119,389)
2030	539,369	307,113	(1,659)	194,009	234,244	(194,338)	173,024	(21,314)	98,075		(119,389)
2031	539,369	307,113	(1,674)	194,009	240,327	(200,406)	173,024	(27,382)	92,007		(119,389)
2032	539,369	307,113	(1,685)	194,009	246,854	(206,922)	173,024	(33,898)	85,491		(119,389)
2033	539,369	307,113	(1,696)	194,009	253,910	(213,967)	173,024	(40,943)	78,446		(119,389)
2034	539,369	307,113	(1,706)	194,009	261,530	(221,577)	173,024	(48,553)	70,836		(119,389)
2035	539,369	307,113	(1,715)	194,009	269,731	(229,769)	173,024	(56,745)	62,644		(119,389)
2036	539,369	307,113	(1,721)	194,009	278,532	(238,564)	173,024	(65,540)	53,849		(119,389)
2037	539,369	307,113	(1,727)	194,009	288,056	(248,082)	173,024	(75,058)	44,331		(119,389)
2038	539,369	307,113	(1,732)	194,009	298,219	(258,240)	173,024	(85,216)	34,173		(119,389)
TRANSMISSION TOTALS	29,743,805	15,330,494	(51,059)	9,445,917	11,424,387	(6,405,934)	8,670,028	2,386,833	4,615,740	0	(4,331,548)

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.

	Intertie capacity ownership accrual revenues	Amortization of capitalized bond premiums	Capitalization adjustment	Delivery facilities sale proceeds	Fiber optic lease advance proceeds	Fiber optic lease accrual revenues
6/INCLUDES:	(3,467)	725				
7/INCLUDES:	(2,638)	2,015	(16,848)	2,816		
8/INCLUDES:	(3,518)	3,007	(20,764)	14,029		
9/INCLUDES:	(3,335)	4,190	(20,764)	5,149	3,104	(235)
10/INCLUDES:	(3,335)	4,654	(19,720)			(310)
11/INCLUDES:	(3,335)	4,654	(20,763)	56,327	310	(209)

TABLE 4.4A
REVISED REVENUE TEST
INCOME STATEMENT
($thousands)

		A FY 2002	B FY 2003
1	REVENUES FROM PROPOSED RATES	675,684	686,581
2	OPERATING EXPENSES		
3	OPERATION AND MAINTENANCE	235,686	229,810
4	INTER-BUSINESS LINE EXPENSES	77,320	77,303
5	FEDERAL PROJECTS DEPRECIATION	181,734	194,009
6	TOTAL OPERATING EXPENSES	494,740	501,122
7	INTEREST EXPENSE		
8	INTEREST ON FEDERAL INVESTMENT -		
9	ON APPROPRIATED FUNDS	66,904	65,280
10	ON LONG-TERM DEBT	138,609	144,768
11	INTEREST CREDIT ON CASH RESERVES	(7,662)	(9,975)
12	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,220	3,220
13	CAPITALIZATION ADJUSTMENT	(19,618)	(20,174)
14	AFUDC	(5,040)	(5,225)
15	NET INTEREST EXPENSE	176,413	177,894
16	TOTAL EXPENSES	671,153	679,016
17	NET REVENUES	4,531	7,565

TABLE 4.4B
TRANSMISSION REVENUE REQUIREMENT
REVISED REVENUE TEST
STATEMENT OF CASH FLOWS
($thousands)

		A FY 2002	B FY 2003
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	4,531	7,565
3	EXPENSES NOT REQUIRING CASH:		
4	FEDERAL PROJECTS DEPRECIATION	181,734	194,009
5	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	3,220	3,220
6	CAPITALIZATION ADJUSTMENT	(19,618)	(20,174)
7	ACCRUAL REVENUES (AC INTERTIE/FIBER)	(4,031)	(4,031)
8	CASH PROVIDED BY CURRENT OPERATIONS	165,836	180,589
9	CASH USED FOR CAPITAL INVESTMENTS:		
10	INVESTMENT IN:		
11	UTILITY PLANT	(252,300)	(248,416)
12	CASH USED FOR CAPITAL INVESTMENTS	(252,300)	(248,416)
13	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
14	INCREASE IN LONG-TERM DEBT	252,300	248,416
15	REPAYMENT OF LONG-TERM DEBT	(107,604)	(116,544)
16	REPAYMENT OF CAPITAL APPROPRIATIONS	(23,913)	(26,247)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	120,783	105,625
18	ANNUAL INCREASE (DECREASE) IN CASH	34,319	37,798

TABLE 4.5
FEDERAL COLUMBIA RIVER TRANSMISSION SYSTEM
TRANSMISSION REVENUES FROM PROPOSED RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

	A	B	C	D	E	F	G	H	I	J	K
YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT E)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	IRRIGATION AMORTIZATION (STATEMENT C)	NET POSITION (K=H-I-J)
COMBINED CUMULATIVE											
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
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	125,961	145,411 /5/6	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	124,457	114,383 /7	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	125,130	129,855 /8	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	147,176	135,259 /9	139,784		(4,525)
COST EVALUATION PERIOD											
2000	554,132	264,064		153,955	163,035	(26,922)	153,955	108,322 /10	114,587		(6,265)
2001	564,166	270,138		153,955	172,193	(32,120)	153,955	158,819 /11	59,060		99,759
RATE APPROVAL PERIOD											
2002	674,822	313,006		181,734	176,442	3,640	161,305	164,945	131,517		33,428
2003	685,689	307,113		194,009	177,983	6,584	173,024	179,608	142,791		36,817

REPAYMENT PERIOD	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C PURCHASE AND EXCHANGE POWER (STATEMENT E)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	J IRRIGATION AMORTIZATION (STATEMENT C)	K NET POSITION (K=H-I-J)
2004	685,689	307,113	(1,041)	194,009	181,030	4,578	173,024	177,602	140,785		36,817
2005	685,689	307,113	(1,073)	194,009	179,522	6,118	173,024	179,142	142,325		36,817
2006	685,689	307,113	(1,104)	194,009	181,895	3,776	173,024	176,800	139,983		36,817
2007	685,689	307,113	(1,134)	194,009	178,102	7,599	173,024	180,623	143,806		36,817
2008	685,689	307,113	(1,164)	194,009	178,351	7,380	173,024	180,404	143,587		36,817
2009	685,689	307,113	(1,193)	194,009	181,312	4,448	173,024	177,472	140,655		36,817
2010	685,689	307,113	(1,221)	194,009	179,755	6,033	173,024	179,057	142,240		36,817
2011	685,689	307,113	(1,249)	194,009	177,979	7,837	173,024	180,861	144,044		36,817
2012	685,689	307,113	(1,277)	194,009	178,073	7,771	173,024	180,795	143,978		36,817
2013	685,689	307,113	(1,303)	194,009	178,010	7,860	173,024	180,884	144,067		36,817
2014	685,689	307,113	(1,329)	194,009	178,000	7,896	173,024	180,920	144,103		36,817
2015	685,689	307,113	(1,355)	194,009	178,719	7,203	173,024	180,227	143,410		36,817
2016	685,689	307,113	(1,380)	194,009	182,076	3,871	173,024	176,895	140,078		36,817
2017	685,689	307,113	(1,404)	194,009	184,683	1,288	173,024	174,312	137,495		36,817
2018	685,689	307,113	(1,428)	194,009	185,352	643	173,024	173,667	136,850		36,817
2019	685,689	307,113	(1,451)	194,009	186,415	(397)	173,024	172,627	135,810		36,817
2020	685,689	307,113	(1,474)	194,009	186,517	(476)	173,024	172,548	135,731		36,817
2021	685,689	307,113	(1,496)	194,009	189,583	(3,520)	173,024	169,504	132,687		36,817
2022	685,689	307,113	(1,517)	194,009	191,182	(5,098)	173,024	167,926	131,109		36,817
2023	685,689	307,113	(1,538)	194,009	190,428	(4,323)	173,024	168,701	131,884		36,817
2024	685,689	307,113	(1,557)	194,009	195,805	(9,681)	173,024	163,343	126,526		36,817
2025	685,689	307,113	(1,576)	194,009	198,240	(12,097)	173,024	160,927	124,110		36,817
2026	685,689	307,113	(1,594)	194,009	204,261	(18,100)	173,024	154,924	118,107		36,817
2027	685,689	307,113	(1,613)	194,009	208,668	(22,488)	173,024	150,536	113,719		36,817
2028	685,689	307,113	(1,629)	194,009	209,989	(23,793)	173,024	149,231	112,414		36,817
2029	685,689	307,113	(1,644)	194,009	218,775	(32,564)	173,024	140,460	103,643		36,817
2030	685,689	307,113	(1,659)	194,009	224,358	(38,132)	173,024	134,892	98,075		36,817
2031	685,689	307,113	(1,674)	194,009	230,441	(44,200)	173,024	128,824	92,007		36,817
2032	685,689	307,113	(1,685)	194,009	236,968	(50,716)	173,024	122,308	85,491		36,817
2033	685,689	307,113	(1,696)	194,009	244,024	(57,761)	173,024	115,263	78,446		36,817
2034	685,689	307,113	(1,706)	194,009	251,644	(65,371)	173,024	107,653	70,836		36,817
2035	685,689	307,113	(1,715)	194,009	259,845	(73,563)	173,024	99,461	62,644		36,817
2036	685,689	307,113	(1,721)	194,009	268,646	(82,358)	173,024	90,666	53,849		36,817
2037	685,689	307,113	(1,727)	194,009	278,170	(91,876)	173,024	81,148	44,331		36,817
2038	685,689	307,113	(1,732)	194,009	288,333	(102,034)	173,024	70,990	34,173		36,817
TRANSMISSION TOTALS	35,157,482	15,330,494	(51,059)	9,445,917	11,057,691	(625,561)	8,670,028	8,167,206	4,615,740	0	1,448,825

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.

	Intertie capacity ownership accrual revenues	Amortization of capitalized bond premiums	Capitalization adjustment	Delivery facilities sale proceeds	Fiber optic lease advance proceeds	Fiber optic lease accrual revenues
6/INCLUDES:	(3,467)	725				
7/INCLUDES:	(2,638)	2,015	(16,848)	2,816		
8/INCLUDES:	(3,518)	3,007	(20,764)	14,029		
9/INCLUDES:	(3,335)	4,190	(20,764)	5,149	3,104	(235)
10/INCLUDES:	(3,335)	4,654	(19,720)			(310)
11/INCLUDES:	(3,335)	4,654	(20,763)	56,327	310	(209)

5. REVENUE REQUIREMENT 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 and expenses among the various users of the Federal Columbia River Transmission System (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", RA6120.2, issued by the Secretary of Energy provides guidance to Federal power marketing agencies regarding repayment of the Federal investment. In addition, from time to time policies issued by the Federal Energy Regulatory Commission (FERC) provide guidance on transmission pricing.

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 of the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. §838b. Such transmission system was 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 would be set to also recover:

> *. . . payments provided [in the Administrator's annual budget], and (3) 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 assure 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.*

More recently, 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) of the Federal Power Act, 16 U.S.C. § 824j(a). In applying the Federal Power Act provisions to FERCordered 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.*

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 Revenue Requirement Study.

5.1.2 The BPA Appropriations Refinancing Act

As in the prior rate period, BPA's transmission rates for the FY 2002 - 2003 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 also 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 has therefore 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 largely been established 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 were first approved by the Secretary of the Interior on April 3, 1963. These criteria were refined and submitted to the Secretary and the Federal Power Commission (the predecessor agency to FERC) in support of BPA's rate filing in September 1965.

The repayment policy was presented to Congress for its consideration for the authorization of the Grand Coulee Dam Third Powerhouse in June 1966. The underlying theory of repayment was discussed in the House of Representatives' Report related to 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 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 are set forth in the Department of the Interior Manual, Park 730, Chapter 1:

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

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

To achieve a greater degree of uniformity in a repayment policy for all Federal power marketing agencies, the Deputy Assistant Secretary of the Department of 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 Department of Interior 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 on September 20, 1979, as amended on October 1, 1983.

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

1. Pay all annual costs of operating and maintaining the Federal system;
2. Pay the cost each fiscal year 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 expense each year on the unamortized portion of the Federal investment financed with appropriated funds at the interest rates established for each Federal 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:

   a. each dollar of power investments and obligations in the Federal generating projects within 50 years after the projects become revenue producing, except as otherwise provided by law;

   b. each annual increment of Federal transmission investments and obligations within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less.

   c. the cost of each replacement of the Federal system within its service life up to a maximum of 50 years; and

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.

APPENDIX A

THE REPAYMENT PROGRAM

1. REPAYMENT PROGRAM OPERATION

1.1. Purpose

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

1.2. Computation of Revenues Available for Interest and Amortization

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

(1) $\text{revenues available for interest and amortization}_i =$

$\text{revenues}_i - \text{expenses}_i, \; i=1,2,\ldots,n,$

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

1.3 Computation of Revenues Available for Amortization Payments

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

(2) revenues available for interest and amortization$_i$ -

$$\text{interest expense}_i = \sum_{j=1}^{m} \text{amortization payment}_{ij}, \quad i=1,2,\ldots n,$$

where m is the total number of Federal investments.

1.4. Computation of Principal Payments Given Due Dates

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

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

1.5. Ordering of Payments According to Highest Interest First Constraint

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

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

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

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

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

1.6. Iteration Towards A Solution

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

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

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

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

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

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

2. DETERMINING A SUFFICIENT REVENUE LEVEL

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

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

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

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

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

BPA's current long-term bonds issued to the U.S. Treasury consist of term bonds and callable bonds. The term bonds cannot be prepaid. Their amortization and the revenues required for such bonds are therefore excluded from the above calculations. The remaining bonds are callable bonds and have provisions that allow for early redemption before the maturity date—

five years after the date of the issuance on some older bonds and longer periods on some of the more recently issued bonds. In addition, a premium must be paid if a bond is repaid before its due date. The premium that must be paid decreases with the age of the bond. This premium affects the repayment process in two ways.

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

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

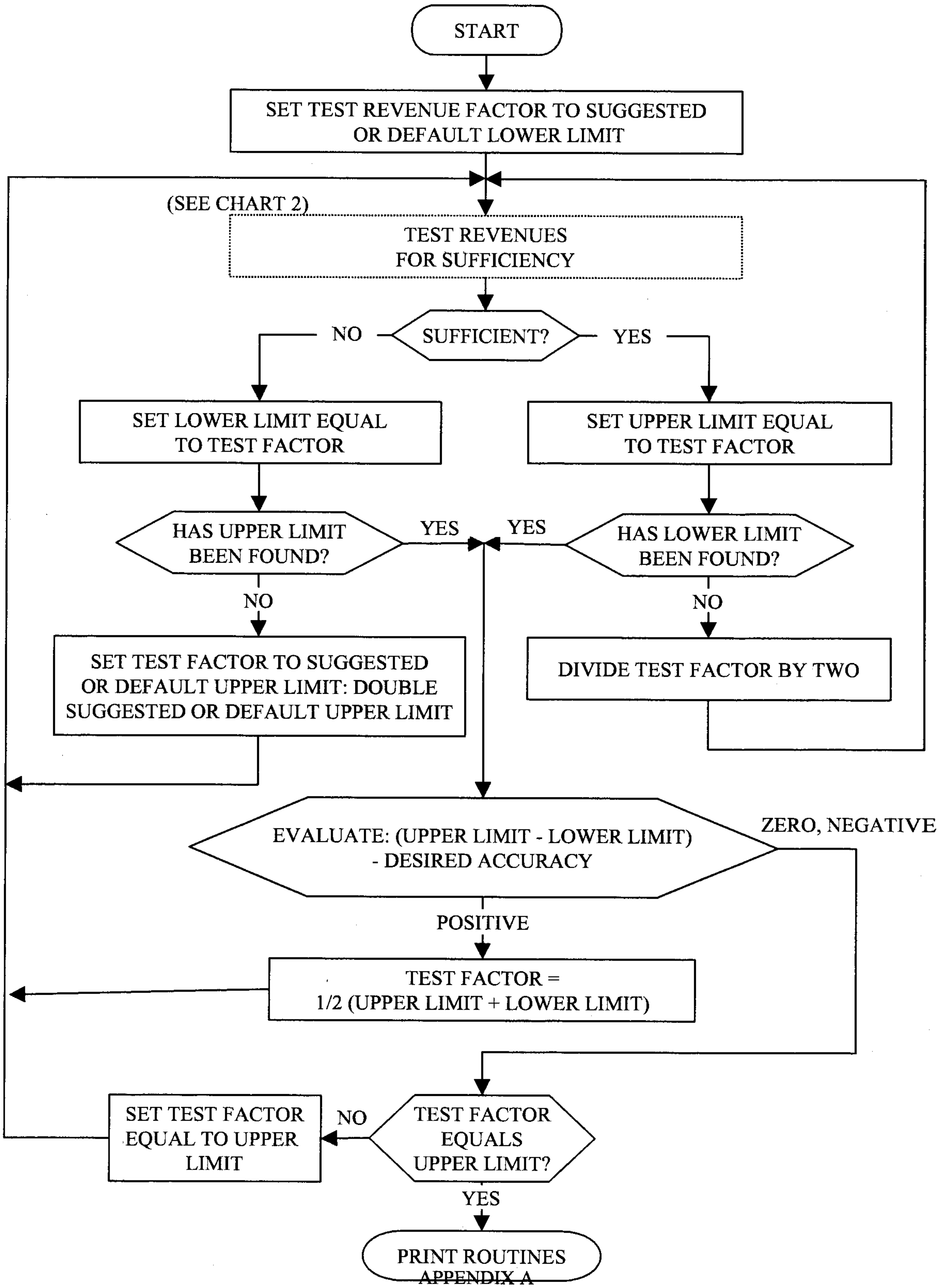
4. INTEREST INCOME

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

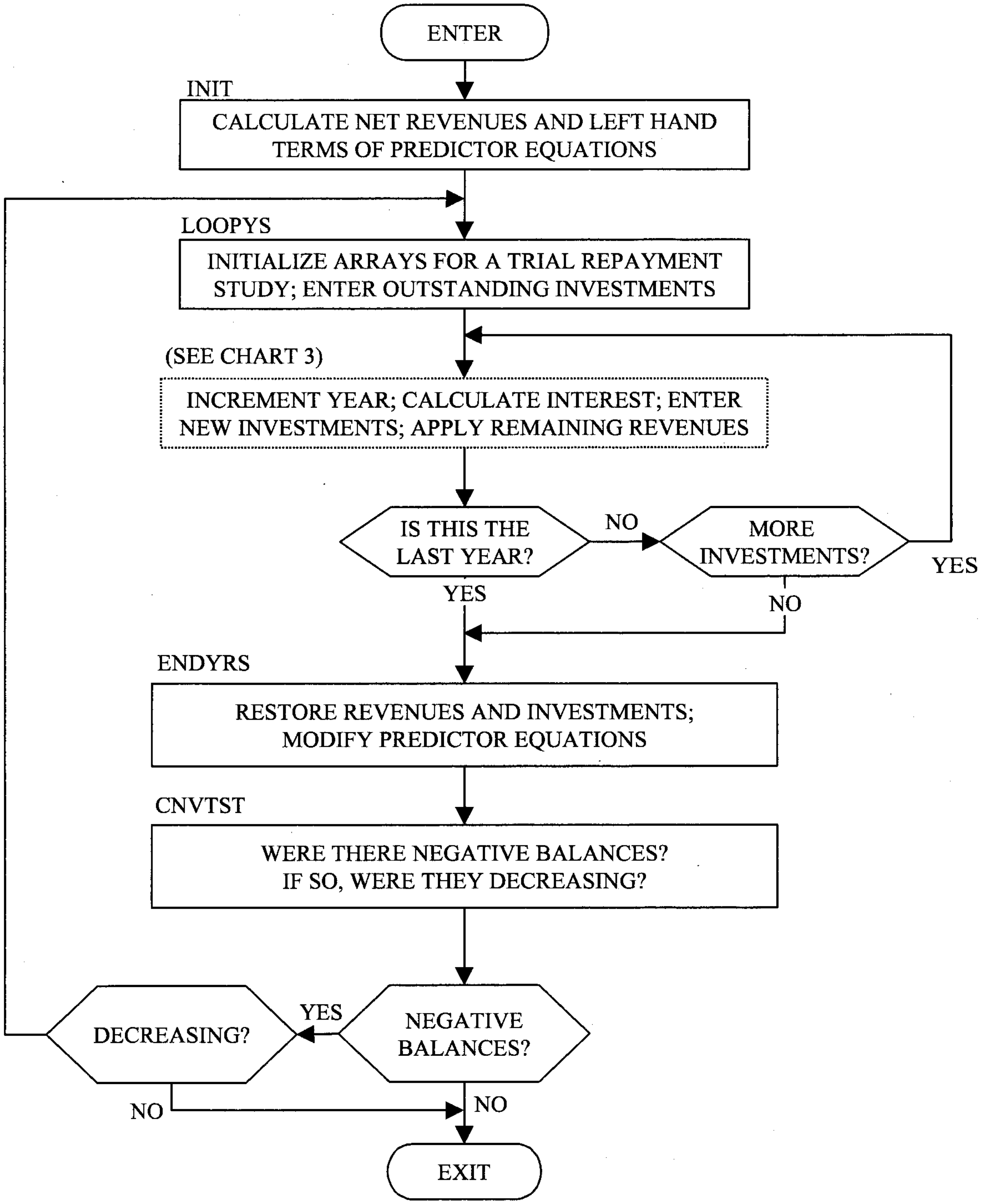
5. FLOW CHARTS

The following three pages contain flow charts associated with the repayment study program. The first chart shows the binary search process. The second chart shows the test for sufficiency. The third chart shows the application of revenues. See Chapter 14 of Documentation for Revenue Requirement Study, TR-02-FS-BPA-01A.

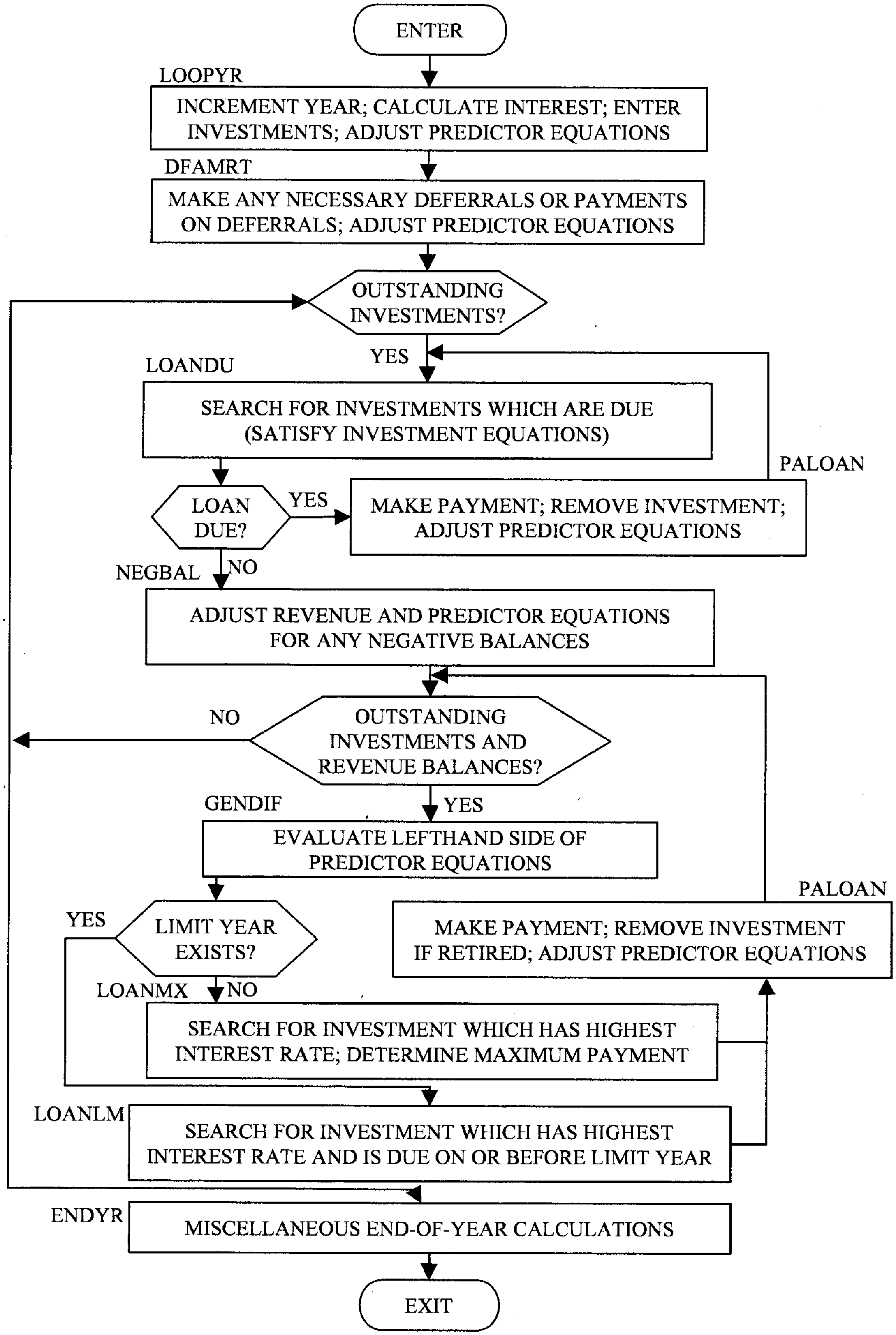
REPAYMENT PROGRAM
(BINARY SEARCH)
CHART 1



REPAYMENT PROGRAM
(TEST FOR SUFFICIENCY)
CHART 2



REPAYMENT PROGRAM
(APPLICATION OF REVENUES)
CHART 3



6. DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table A.1 shows the amortization results from the Transmission repayment studies for FY 2002 and 2003, summarized by bonds and appropriations due and discretionary, by year.

Tables A.2 through A.3, A through D, show the results from the Transmission repayment studies for FY 2002 and 2003, respectively, using revenues from current rates. Table A.4 provides the application of amortization through the repayment period for transmission based upon the revenues forecast using current rates.

Tables A.2A and A.3A display the repayment program results for transmission for FY 2002 and 2003. Column A shows the applicable fiscal year. Column B shows the total investment costs of the transmission projects through the cost evaluation period. *See* Chapter 4 of Documentation for Revenue Requirement Study, TR-02-FS-BPA-01A. In Column C, forecasted replacements required to maintain the system are displayed through the repayment period. *See* Chapter 11 of Documentation for Revenue Requirement Study, TR-02-FS-BPA-01A. Column D shows the cumulative dollar amount of the transmission investment placed in service. This is comprised of historical plant-in-service, planned replacements and additions to plant through the cost evaluation period, and replacements from the end of the cost evaluation period to the end of the repayment study period. For these studies all additional plant is assumed to be financed by bonds.

In Column E scheduled amortization payments for transmission are displayed for each year of the repayment period. Unamortized transmission obligations, shown in column G, are determined by taking the previous year's unamortized amount, adding any replacements and subtracting amortization.

Tables A.2B and A.3B display planned principal payments by fiscal year for Federal transmission obligations. Shown on these tables are the principal payments associated with appropriations and BPA bonds.

Tables A.2C and A.3C show the planned interest payments by fiscal year for Federal transmission obligations. Shown on these tables are the interest payments associated with appropriations and BPA bonds.

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

Table A.4 lists by year through the 35-year repayment period the application of the transmission amortization payments, consistent with the revised repayment studies, by project. The projected annual amortization payments on the transmission obligations are identified by the project name, in-service date, due date, and interest rate. The amount of the obligation is shown as both the original gross amount due and the net amount after all prior amortization payments.

TABLE A.1

TRANSMISSION AMORTIZATION
REPAYMENT STUDY FOR FINAL PROPOSAL 2002
FY 2002-2003
(000s)

Maturing/Due		
Bonds		
	2002	40,000
	2003	94,378
		134,378
Appropriations		
	2002	23,913
	2003	26,247
		50,160
TOTAL DUE		**184,538**

Scheduled But Not Yet Due		
Bonds		
	2002	67,644
	2003	22,222
		89,866
Appropriations		
	2002	0
	2003	0
		0
TOTAL DUE		**89,866**

Total by Year		
Bonds		
	2002	107,644
	2003	116,600
		224,244
Appropriations		
	2002	23,913
	2003	26,247
		50,160
TOTAL AMORTIZATION	2002	**131,557**
	2003	**142,847**
		274,404

TABLE A.2A

2B

FY 2002

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

A	B		C		D		E		F		G
	INVESTMENT PLACED IN SERVICE										
FISCAL YEAR ENDING SEPT 30	INITIAL 1/ PROJECT THRU 9-30	+	REPLACE-MENTS THRU 9-30	=	CUMULATIVE AMOUNT IN SERVICE	-	AMORTI-ZATION 9-30	-	DISCRETIONARY AMORTIZATION	=	UNAMORTIZED INVESTMENT
CUMULATIVE 1999	4,143,304		981,077		5,124,381		2,498,283				2,626,098
2000	278,371				5,402,752		114,587				2,789,882
2001	210,690				5,613,442		59,064				2,941,508
2002	241,032				5,854,474		148,755				3,033,785
2003			131,031		5,985,505		151,201				3,013,615
2004			134,500		6,120,005		152,648				2,995,467
2005			137,907		6,257,912		152,783				2,980,591
2006			141,220		6,399,132		150,391				2,971,420
2007			144,361		6,543,493		154,141				2,961,640
2008			147,185		6,690,678		153,825				2,955,000
2009			149,676		6,840,354		152,214				2,952,462
2010			151,745		6,992,099		154,141				2,950,066
2011			153,671		7,145,770		154,349				2,949,388
2012			155,624		7,301,394		154,047				2,950,965
2013			157,621		7,459,015		153,864				2,954,722
2014			159,659		7,618,674		153,580				2,960,801
2015			161,838		7,780,512		148,598				2,974,041
2016			164,101		7,944,613		145,839				2,992,303
2017			166,388		8,111,001		143,980				3,014,711
2018			168,744		8,279,745		141,920				3,041,535
2019			171,064		8,450,809		140,019				3,072,580
2020			173,341		8,624,150		137,839				3,108,082
2021			175,513		8,799,663		135,363				3,148,232
2022			177,527		8,977,190		132,581				3,193,178
2023			179,416		9,156,606		134,427				3,238,167
2024			181,175		9,337,781		125,233				3,294,109
2025			182,756		9,520,537		121,375				3,355,490
2026			184,282		9,704,819		117,144				3,422,628
2027			185,836		9,890,655		115,026				3,493,438
2028			187,376		10,078,031		112,424				3,568,390
2029			188,951		10,266,982		104,054				3,653,287
2030			190,615		10,457,597		98,707				3,745,195
2031			192,307		10,649,904		92,140				3,845,362
2032			194,003		10,843,907		84,999				3,954,366
2033			195,708		11,039,615		76,693				4,073,381
2034			197,431		11,237,046		68,041				4,202,771
2035			199,086		11,436,132		58,379				4,343,478
2036			200,628		11,636,760		48,336				4,495,770
2037			202,041		11,838,801		37,459				4,660,352
TOTALS	4,873,397		6,965,404				7,178,449				

TABLE A.2B

2C

FY 2002

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

A	B	C	D	E	F	G	H	I	J
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION		
YEAR	APPROPRIATIONS		BONDS		APPROPRIATIONS		APPROPRIATIONS		IRRIGATION
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 1/	TRANS	GEN	AMORTIZATION
2002	23,913		124,842						
2003	39,354		111,847						
2004	103,848		48,800						
2005	7,816		144,967						
2006	15,739		134,652						
2007	24,474		129,667						
2008	10,913		142,912						
2009	36,390		115,824						
2010	142,041		12,100						
2011	114,349		40,000						
2012	114,047		40,000						
2013	153,864								
2014	104,660		48,920						
2015	38,976		109,622						
2016			145,839						
2017			143,980						
2018			141,920						
2019			140,019						
2020			137,839						
2021			135,363						
2022			132,581						
2023			134,427						
2024			125,233						
2025			121,375						
2026			117,144						
2027			115,026						
2028			112,424						
2029			104,054						
2030			98,707						
2031			92,140						
2032			84,999						
2033			76,693						
2034			68,041						
2035			58,379						
2036			48,336						
2037			37,459						
TOTALS	930,384		3,576,131						

LEGEND
TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

TABLE A.2C

2E

FY 2002

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

A	B	C	D	E	F	G	H	I
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION	
YEAR	APPROPRIATIONS		BONDS 1/		APPROPRIATIONS		APPROPRIATIONS	
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 2/	TRANS	GEN
2002	66,904		138,994					
2003	65,280		139,181					
2004	62,528		140,518					
2005	55,028		147,915					
2006	54,488		150,878					
2007	53,394		148,252					
2008	51,686		150,306					
2009	50,921		152,711					
2010	48,292		153,441					
2011	38,004		163,549					
2012	29,724		172,159					
2013	21,485		180,607					
2014	10,375		192,027					
2015	2,810		204,600					
2016			210,194					
2017			212,077					
2018			214,161					
2019			216,085					
2020			218,288					
2021			220,786					
2022			223,589					
2023			221,764					
2024			230,977					
2025			234,854					
2026			239,103					
2027			241,230					
2028			243,858					
2029			252,243					
2030			257,605					
2031			264,187					
2032			271,339					
2033			279,656					
2034			288,318					
2035			297,989					
2036			308,038					
2037			318,921					
TOTALS	610,919		7,700,400					

LEGEND
TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ NET OF INTEREST INCOME AND AFUDC

2/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

TABLE A.2D

2H

FY 2002

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

A FISCAL YEAR ENDING SEPT 30	B GENERATION UNAMORTIZED INVESTMENT	C TERM SCHEDULE	D TRANSMISSION UNAMORTIZED INVESTMENT	E TERM SCHEDULE
CUMULATIVE 1999			2,626,098	4,178,751
2000			2,789,882	4,342,887
2001			2,941,508	4,451,783
2002			3,033,785	4,628,902
2003			3,013,615	4,639,308
2004			2,995,467	4,707,988
2005			2,980,591	4,704,579
2006			2,971,420	4,760,060
2007			2,961,640	4,768,693
2008			2,955,000	4,789,665
2009			2,952,462	4,856,752
2010			2,950,066	4,970,070
2011			2,949,388	5,060,501
2012			2,950,965	5,134,820
2013			2,954,722	5,165,531
2014			2,960,801	5,085,907
2015			2,974,041	5,012,755
2016			2,992,303	4,932,881
2017			3,014,711	4,787,873
2018			3,041,535	4,731,202
2019			3,072,580	4,744,814
2020			3,108,082	4,835,313
2021			3,148,232	4,947,589
2022			3,193,178	5,031,037
2023			3,238,167	5,103,853
2024			3,294,109	5,285,028
2025			3,355,490	5,352,851
2026			3,422,628	5,537,133
2027			3,493,438	5,722,969
2028			3,568,390	5,747,945
2029			3,653,287	5,836,896
2030			3,745,195	5,918,660
2031			3,845,362	6,095,292
2032			3,954,366	5,981,015
2033			4,073,381	6,026,723
2034			4,202,771	5,965,754
2035			4,343,478	6,015,247
2036			4,495,770	6,014,271
2037			4,660,352	5,984,327

TABLE A.3A

2B

FY 2003

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

REPAYMENT STUDY

(ALL AMOUNTS IN $1000)

TRANSMISSION

INVESTMENT PLACED IN SERVICE

A	B		C		D		E		F		G
FISCAL YEAR ENDING SEPT 30	INITIAL 1/ PROJECT THRU 9-30	+	REPLACE- MENTS THRU 9-30	=	CUMULATIVE AMOUNT IN SERVICE	-	AMORTI- ZATION 9-30	-	DISCRETIONARY AMORTIZATION	=	UNAMORTIZED INVESTMENT
CUMULATIVE 1999	4,144,453		981,077		5,125,530		2,499,432				2,626,098
2000	278,371				5,403,901		118,296				2,786,173
2001	210,690				5,614,591		63,580				2,933,283
2002	241,032				5,855,623		130,398				3,043,917
2003	247,205				6,102,828		153,288				3,137,834
2004			137,969		6,240,797		152,582				3,123,221
2005			141,467		6,382,264		152,732				3,111,956
2006			144,854		6,527,118		150,354				3,106,456
2007			148,057		6,675,175		154,119				3,100,394
2008			150,933		6,826,108		153,821				3,097,506
2009			153,462		6,979,570		152,227				3,098,741
2010			155,555		7,135,125		154,188				3,100,108
2011			157,500		7,292,625		154,426				3,103,182
2012			159,468		7,452,093		154,159				3,108,491
2013			161,479		7,613,572		154,018				3,115,952
2014			163,526		7,777,098		153,783				3,125,695
2015			165,720		7,942,818		149,162				3,142,253
2016			168,004		8,110,822		146,346				3,163,911
2017			170,318		8,281,140		145,508				3,188,721
2018			172,710		8,453,850		144,884				3,216,547
2019			175,079		8,628,929		143,276				3,248,350
2020			177,412		8,806,341		139,196				3,286,566
2021			179,650		8,985,991		136,586				3,329,630
2022			181,731		9,167,722		133,664				3,377,697
2023			183,690		9,351,412		134,968				3,426,419
2024			185,513		9,536,925		126,181				3,485,751
2025			187,148		9,724,073		122,201				3,550,698
2026			188,720		9,912,793		117,812				3,621,606
2027			190,316		10,103,109		115,007				3,696,915
2028			191,894		10,295,003		112,420				3,776,389
2029			193,510		10,488,513		101,580				3,868,319
2030			195,226		10,683,739		96,077				3,967,468
2031			196,977		10,880,716		91,295				4,073,150
2032			198,732		11,079,448		84,494				4,187,388
2033			200,499		11,279,947		76,179				4,311,708
2034			202,283		11,482,230		67,516				4,446,475
2035			203,993		11,686,223		57,716				4,592,752
2036			205,585		11,891,808		47,569				4,750,768
2037			207,045		12,098,853		36,564				4,921,249
2038			208,379		12,307,232		24,672				5,104,956
TOTALS	5,121,751		7,185,481				7,202,276				

1/ GROSS INITIAL PROJECT INVESTMENT, RETIREMENTS INCLUDED

TABLE A.3B

2C

FY 2003

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

A	B	C	D	E	F	G	H	I	J
FISCAL YEAR	BONNEVILLE POWER ADMINISTRATION APPROPRIATIONS		BONNEVILLE POWER ADMINISTRATION BONDS		CORPS OF ENGINEERS APPROPRIATIONS		BUREAU OF RECLAMATION APPROPRIATIONS		IRRIGATION
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 1/	TRANS	GEN	AMORTIZATION
2003	31,309		121,979						
2004	103,782		48,800						
2005	7,816		144,916						
2006	15,739		134,615						
2007	24,474		129,645						
2008	10,913		142,908						
2009	36,289		115,938						
2010	142,088		12,100						
2011	114,426		40,000						
2012	114,159		40,000						
2013	154,018								
2014	104,863		48,920						
2015	46,595		102,567						
2016			146,346						
2017			145,508						
2018			144,884						
2019			143,276						
2020			139,196						
2021			136,586						
2022			133,664						
2023			134,968						
2024			126,181						
2025			122,201						
2026			117,812						
2027			115,007						
2028			112,420						
2029			101,580						
2030			96,077						
2031			91,295						
2032			84,494						
2033			76,179						
2034			67,516						
2035			57,716						
2036			47,569						
2037			36,564						
2038			24,672						
TOTALS	906,471		3,484,099						

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

TABLE A.3C

2E

FY 2003

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

A	B	C	D	E	F	G	H	I
FISCAL	BONNEVILLE POWER ADMINISTRATION				CORPS OF ENGINEERS		BUREAU OF RECLAMATION	
YEAR	APPROPRIATIONS		BONDS 1/		APPROPRIATIONS		APPROPRIATIONS	
ENDING SEPT 30	TRANS	GEN	TRANS	CONS & GEN	TRANS	GEN 2/	TRANS	GEN
2003	65,280		144,130					
2004	63,115		148,042					
2005	55,619		155,420					
2006	55,079		158,369					
2007	53,985		155,728					
2008	52,277		157,764					
2009	51,512		160,152					
2010	48,889		160,842					
2011	38,598		170,923					
2012	30,312		179,504					
2013	22,064		187,919					
2014	10,941		199,303					
2015	3,360		211,531					
2016			217,732					
2017			218,594					
2018			219,242					
2019			220,873					
2020			224,976					
2021			227,608					
2022			230,551					
2023			229,268					
2024			238,074					
2025			242,073					
2026			246,480					
2027			249,304					
2028			251,907					
2029			262,762					
2030			268,280					
2031			273,077					
2032			279,889					
2033			288,215					
2034			296,888					
2035			306,697					
2036			316,850					
2037			327,861					
2038			339,758					
TOTALS	551,031		8,166,586					

LEGEND

TRANS = TRANSMISSION
GEN = GENERATION
CONS = CONSERVATION

1/ NET OF INTEREST INCOME AND AFUDC

2/ INCLUDES PAYMENTS FOR LOWER SNAKE FISH & WILDLIFE

TABLE A.3D

2H

FY 2003

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

A FISCAL YEAR ENDING SEPT 30	B GENERATION UNAMORTIZED INVESTMENT	C GENERATION TERM SCHEDULE	D TRANSMISSION UNAMORTIZED INVESTMENT	E TRANSMISSION TERM SCHEDULE
CUMULATIVE 1999			2,626,098	4,179,900
2000			2,786,173	4,344,036
2001			2,933,283	4,452,932
2002			3,043,917	4,630,051
2003			3,137,834	4,756,631
2004			3,123,221	4,828,780
2005			3,111,956	4,828,931
2006			3,106,456	4,888,046
2007			3,100,394	4,900,375
2008			3,097,506	4,925,095
2009			3,098,741	4,995,968
2010			3,100,108	5,113,096
2011			3,103,182	5,207,356
2012			3,108,491	5,285,519
2013			3,115,952	5,320,088
2014			3,125,695	5,244,331
2015			3,142,253	5,175,061
2016			3,163,911	5,099,090
2017			3,188,721	4,958,012
2018			3,216,547	4,896,033
2019			3,248,350	4,913,660
2020			3,286,566	5,008,230
2021			3,329,630	5,124,643
2022			3,377,697	5,212,295
2023			3,426,419	5,289,385
2024			3,485,751	5,474,898
2025			3,550,698	5,547,113
2026			3,621,606	5,735,833
2027			3,696,915	5,926,149
2028			3,776,389	5,955,643
2029			3,868,319	6,049,153
2030			3,967,468	6,134,379
2031			4,073,150	6,315,681
2032			4,187,388	6,206,133
2033			4,311,708	6,256,632
2034			4,446,475	6,200,515
2035			4,592,752	6,254,915
2036			4,750,768	6,258,896
2037			4,921,249	6,233,956
2038			5,104,956	6,204,404

Table A.4

Application of Amortization
Transmission
FY 2003 Repayment Study

INVESTMENT PAID

(ALL AMOUNT IN $1000)

	PROJECT	IN-SERVICE	DUE	GROSS	NET	RATE	REPLACEMENT	AMOUNT
2000	BONNEVILLE POWER ADMINISTRATION	1955	2000	11,827	11,827	.06620		11,827
	BPA PROGRAM	1992	2000	92,125	92,125	.06600		92,125
	BONNEVILLE POWER ADMINISTRATION	1955	2000	10,283	10,283	.06620	R	10,283
	BPA PROGRAM	1995	2025	8,442	8,442	.07700		352
	TOTAL							114,587
2001	BONNEVILLE POWER ADMINISTRATION	1956	2001	14,573	14,573	.06710		14,573
	BONNEVILLE POWER ADMINISTRATION	1956	2001	32,221	32,221	.06710	R	32,221
	BPA PROGRAM	1995	2025	8,442	8,090	.07700		8,090
	BPA PROGRAM	1995	2025	65,000	65,000	.07700		4,180
	TOTAL							59,064
2002	BONNEVILLE POWER ADMINISTRATION	1957	2002	7,933	7,933	.06790		7,933
	BPA PROGRAM	1999	2002	40,000	40,000	.06200		40,000
	BONNEVILLE POWER ADMINISTRATION	1957	2002	15,980	15,980	.06790	R	15,980
	BPA PROGRAM	1995	2025	65,000	60,820	.07700		60,820
	BPA PROGRAM	1995	2025	41,491	41,491	.07700		6,824
	TOTAL							131,557
2003	BPA PROGRAM	1996	2003	50,000	50,000	.05900		50,000
	BPA PROGRAM	1996	2003	4,378	4,378	.05900		4,378
	BPA PROGRAM	2000	2003	40,000	40,000	.06400		40,000
	BONNEVILLE POWER ADMINISTRATION	1958	2003	15,593	15,593	.06840		15,593
	BONNEVILLE POWER ADMINISTRATION	1958	2003	10,654	10,654	.06840	R	10,654
	BPA PROGRAM	1995	2025	41,491	34,667	.07700		22,222
	TOTAL							142,847
2004	BPA PROGRAM	1999	2004	26,200	26,200	.05950		26,200
	BPA PROGRAM	1997	2004	22,600	22,600	.06800		22,600
	BONNEVILLE POWER ADMINISTRATION	1959	2004	8,157	8,157	.06880		8,157
	BONNEVILLE POWER ADMINISTRATION	1959	2004	8,863	8,863	.06880	R	8,863
	BPA PROGRAM	1995	2025	41,491	12,445	.07700		12,445
	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,805	17,805	.07290	R	17,805
	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,051	12,051	.07290		12,051
	BONNEVILLE POWER ADMINISTRATION	1971	2016	17,766	17,766	.07290	R	17,766
	BONNEVILLE POWER ADMINISTRATION	1971	2016	12,025	12,025	.07290		12,025
	BONNEVILLE POWER ADMINISTRATION	1972	2017	2,873	2,873	.07290	R	2,873
	TOTAL							140,785
2005	BPA PROGRAM	2000	2005	53,500	53,500	.07150		53,500
	BPA PROGRAM	1997	2005	80,000	80,000	.06900		80,000
	BONNEVILLE POWER ADMINISTRATION	1960	2005	4,218	4,218	.06910	R	4,218
	BONNEVILLE POWER ADMINISTRATION	1960	2005	3,598	3,598	.06910		3,598
	BPA PROGRAM	2000	2035	149,593	149,593	.07540		1,009
	TOTAL							142,325
2006	BPA PROGRAM	1996	2006	70,000	70,000	.07050		70,000
	BONNEVILLE POWER ADMINISTRATION	1961	2006	4,468	4,468	.06950		4,468
	BONNEVILLE POWER ADMINISTRATION	1961	2006	11,271	11,271	.06950	R	11,271
	BPA PROGRAM	2000	2035	149,593	148,584	.07540		54,244
	TOTAL							139,983

2007	BONNEVILLE POWER ADMINISTRATION	1962	2007	19,597	19,597	.06980		19,597
	BPA PROGRAM	1997	2007	111,254	111,254	.06650		111,254
	BONNEVILLE POWER ADMINISTRATION	1962	2007	4,877	4,877	.06980	R	4,877
	BPA PROGRAM	2000	2035	149,593	94,340	.07540		8,078

	TOTAL							143,806
2008	BPA PROGRAM	1998	2008	75,300	75,300	.06000		75,300
	BPA PROGRAM	1998	2008	40,000	40,000	.05750		40,000
	BONNEVILLE POWER ADMINISTRATION	1963	2008	4,876	4,876	.07020		4,876
	BONNEVILLE POWER ADMINISTRATION	1963	2008	904	904	.07020		904
	BONNEVILLE POWER ADMINISTRATION	1963	2008	4,330	4,330	.07020	R	4,330
	BONNEVILLE POWER ADMINISTRATION	1963	2008	803	803	.07020	R	803
	BPA PROGRAM	2000	2035	149,593	86,262	.07540		17,374

	TOTAL							143,587
2009	BPA PROGRAM	1998	2009	72,700	72,700	.06000		72,700
	BONNEVILLE POWER ADMINISTRATION	1964	2009	4,151	4,151	.07060		4,151
	BONNEVILLE POWER ADMINISTRATION	1964	2009	5,738	5,738	.07060	R	5,738
	BPA PROGRAM	2000	2035	149,593	68,888	.07540		58,066

	TOTAL							140,655
2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	7,248	7,248	.07090	R	7,248
	BONNEVILLE POWER ADMINISTRATION	1965	2010	3,706	3,706	.07090		3,706
	BONNEVILLE POWER ADMINISTRATION	1965	2010	5,202	5,202	.07090		5,202
	BONNEVILLE POWER ADMINISTRATION	1965	2010	10,171	10,171	.07090	R	10,171
	FISH, WILDLIFE & ENVIRONMENTAL	1995	2010	12,100	12,100	.07200		12,100
	BPA PROGRAM	2000	2035	149,593	10,822	.07540		10,822
	BPA PROGRAM	2000	2031	15,675	15,675	.07540		15,675
	BONNEVILLE POWER ADMINISTRATION	1972	2017	3,980	3,980	.07290		3,980
	BONNEVILLE POWER ADMINISTRATION	1972	2017	21,170	21,170	.07290	R	21,170
	BONNEVILLE POWER ADMINISTRATION	1972	2017	29,326	29,326	.07290		29,326
	BONNEVILLE POWER ADMINISTRATION	1973	2018	10,491	10,491	.07280	R	10,491
	BONNEVILLE POWER ADMINISTRATION	1973	2018	16,368	16,368	.07280		12,349

	TOTAL							142,240
2011	BPA PROGRAM	1998	2011	40,000	40,000	.06200		40,000
	BONNEVILLE POWER ADMINISTRATION	1966	2011	11,830	11,830	.07130		11,830
	BONNEVILLE POWER ADMINISTRATION	1966	2011	3,049	3,049	.07130	R	3,049
	BONNEVILLE POWER ADMINISTRATION	1966	2011	6,647	6,647	.07130		6,647
	BONNEVILLE POWER ADMINISTRATION	1966	2011	1,714	1,714	.07130	R	1,714
	BONNEVILLE POWER ADMINISTRATION	1973	2018	16,368	4,019	.07280		4,019
	BONNEVILLE POWER ADMINISTRATION	1973	2018	21,656	21,656	.07280	R	21,656
	BONNEVILLE POWER ADMINISTRATION	1973	2018	33,788	33,788	.07280		33,788
	BONNEVILLE POWER ADMINISTRATION	1970	2015	3,003	3,003	.07270	R	3,003
	BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	24,412	.07270		18,338

	TOTAL							144,044
2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	19,003	19,003	.07160		19,003
	BONNEVILLE POWER ADMINISTRATION	1967	2012	4,566	4,566	.07160	R	4,566
	BONNEVILLE POWER ADMINISTRATION	1967	2012	14,300	14,300	.07160		14,300
	BONNEVILLE POWER ADMINISTRATION	1967	2012	3,436	3,436	.07160	R	3,436
	FISH, WILDLIFE & ENVIRONMENTAL	1997	2012	40,000	40,000	.06950		40,000
	BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	6,074	.07270		6,074
	BONNEVILLE POWER ADMINISTRATION	1970	2015	7,995	7,995	.07270	R	7,995
	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	64,977	.07270		48,604

	TOTAL							143,978

2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	41,070	41,070	.07200		41,070
	BONNEVILLE POWER ADMINISTRATION	1968	2013	8,076	8,076	.07200	R	8,076
	BONNEVILLE POWER ADMINISTRATION	1968	2013	23,202	23,202	.07200		23,202
	BONNEVILLE POWER ADMINISTRATION	1968	2013	4,562	4,562	.07200	R	4,562
	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	16,373	.07270		16,373
	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,079	12,079	.07270		12,079
	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	20,984	.07270	R	20,984
	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,563	12,563	.07270		12,563
	BONNEVILLE POWER ADMINISTRATION	1974	2019	21,826	21,826	.07270	R	5,158
	TOTAL							144,067
2014	BONNEVILLE POWER ADMINISTRATION	1969	2014	205	205	.07230	R	205
	BPA PROGRAM	1999	2014	48,920	48,920	.05900		48,920
	BONNEVILLE POWER ADMINISTRATION	1969	2014	384	384	.07230		384
	BONNEVILLE POWER ADMINISTRATION	1969	2014	22,537	22,537	.07230	R	22,537
	BONNEVILLE POWER ADMINISTRATION	1969	2014	42,237	42,237	.07230		42,237
	BONNEVILLE POWER ADMINISTRATION	1974	2019	21,826	16,668	.07270	R	16,668
	BONNEVILLE POWER ADMINISTRATION	1975	2020	17,158	17,158	.07250		13,152
	TOTAL							144,103
2015	FISH, WILDLIFE & ENVIRONMENTAL	2000	2015	19,603	19,603	.07240		19,603
	BONNEVILLE POWER ADMINISTRATION	1975	2020	17,158	4,006	.07250		4,006
	BONNEVILLE POWER ADMINISTRATION	1975	2020	11,742	11,742	.07250	R	11,742
	BONNEVILLE POWER ADMINISTRATION	1975	2020	21,916	21,916	.07250	R	21,916
	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	32,026	.07250		32,026
	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	61,025	.07230		54,117
	TOTAL							143,410
2016	FISH, WILDLIFE & ENVIRONMENTAL	2001	2016	9,086	9,086	.06920		9,086
	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	6,908	.07230		6,908
	BONNEVILLE POWER ADMINISTRATION	1976	2021	2,212	2,212	.07230	R	2,212
	BONNEVILLE POWER ADMINISTRATION	1977	2022	3,948	3,948	.07210		3,948
	BONNEVILLE POWER ADMINISTRATION	1977	2022	5,380	5,380	.07210	R	5,380
	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	33,702	.07210		33,702
	BONNEVILLE POWER ADMINISTRATION	1977	2022	4,981	4,981	.07210	R	4,981
	BPA PROGRAM	2001	2036	201,604	201,604	.07290		73,861
	TOTAL							140,078
2017	FISH, WILDLIFE & ENVIRONMENTAL	2002	2017	9,047	9,047	.06690		9,047
	BPA PROGRAM	2001	2036	201,604	127,743	.07290		127,743
	BPA PROGRAM	2002	2037	231,985	231,985	.07080		705
	TOTAL							137,495
2018	FISH, WILDLIFE & ENVIRONMENTAL	2003	2018	9,274	9,274	.06500		9,274
	BPA PROGRAM	2002	2037	231,985	231,280	.07080		127,576
	TOTAL							136,850
2019	BPA PROGRAM	2002	2037	231,985	103,704	.07080		103,704
	BPA PROGRAM	1994	2034	50,000	50,000	.07050		32,106
	TOTAL							135,810
2020	BPA PROGRAM	1994	2034	50,000	17,894	.07050		17,894
	BPA PROGRAM	1993	2033	110,000	110,000	.06950		110,000
	BPA PROGRAM	2003	2038	237,931	237,931	.06890		7,837
	TOTAL							135,731
2021	BPA PROGRAM	2003	2038	237,931	230,094	.06890		132,687
	TOTAL							132,687

2022	BPA PROGRAM	2003	2038	237,931	97,407	.06890		97,407
	BPA PROGRAM	1994	2034	50,000	50,000	.06850		33,702
	TOTAL							131,109
2023	BPA PROGRAM	1998	2023	106,600	106,600	.05850		106,600
	BPA PROGRAM	1994	2034	50,000	16,298	.06850		16,298
	BPA PROGRAM	1994	2034	108,400	108,400	.06850		8,986
	TOTAL							131,884
2024	BPA PROGRAM	1994	2034	108,400	99,414	.06850		99,414
	BPA PROGRAM	1998	2032	98,900	98,900	.06700		27,112
	TOTAL							126,526
2025	BPA PROGRAM	1998	2032	98,900	71,788	.06700		71,788
	BPA PROGRAM	1998	2028	50,000	50,000	.06650		50,000
	BPA PROGRAM	2004	2049	137,969	137,969	.06300	R	2,322
	TOTAL							124,110
2026	BPA PROGRAM	2004	2049	137,969	135,647	.06300	R	118,107
	TOTAL							118,107
2027	BPA PROGRAM	2004	2049	137,969	17,540	.06300	R	17,540
	BPA PROGRAM	2005	2050	141,467	141,467	.06300	R	96,179
	TOTAL							113,719
2028	BPA PROGRAM	1998	2028	112,400	112,400	.05850		112,400
	BPA PROGRAM	2005	2050	141,467	45,288	.06300	R	14
	TOTAL							112,414
2029	BPA PROGRAM	2005	2050	141,467	45,274	.06300	R	45,274
	BPA PROGRAM	2006	2051	144,854	144,854	.06300	R	58,369
	TOTAL							103,643
2030	BPA PROGRAM	2006	2051	144,854	86,485	.06300	R	86,485
	BPA PROGRAM	2007	2052	148,057	148,057	.06300	R	11,590
	TOTAL							98,075
2031	BPA PROGRAM	2007	2052	148,057	136,467	.06300	R	92,007
	TOTAL							92,007
2032	BPA PROGRAM	2007	2052	148,057	44,460	.06300	R	44,460
	BPA PROGRAM	2008	2053	150,933	150,933	.06300	R	41,031
	TOTAL							85,491
2033	BPA PROGRAM	2008	2053	150,933	109,902	.06300	R	78,446
	TOTAL							78,446
2034	BPA PROGRAM	2008	2053	150,933	31,456	.06300	R	31,456
	BPA PROGRAM	2009	2054	153,462	153,462	.06300	R	39,380
	TOTAL							70,836

2035	BPA PROGRAM	2009	2054	153,462	114,082	.06300	R	62,644
	TOTAL							62,644
2036	BPA PROGRAM	2009	2054	153,462	51,438	.06300	R	51,438
	BPA PROGRAM	2010	2055	155,555	155,555	.06300	R	2,411
	TOTAL							53,849
2037	BPA PROGRAM	2010	2055	155,555	153,144	.06300	R	44,331
	TOTAL							44,331
2038	BPA PROGRAM	2010	2055	155,555	108,813	.06300	R	34,173
	TOTAL							34,173
	GRAND TOTAL							4,561,053
	TOTAL DEFERRAL							0
	NET							4,561,053

COVER LETTER
&
APPENDIX 1

Program Level Expense and Capital Spending – Fiscal Years 2002 and 2003 Close-out of the Program Level Public Process

Department of Energy

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

EXECUTIVE OFFICE

June 28, 2000

In reply refer to: TMP/Ditt2

Dear Program Level Participant:

Subject: Program Level Expense and Capital Spending - Fiscal Years 2002 and 2003
Close-out of the Program Level Public Process

This is a summary report of Bonneville Power Administration's (BPA) dialogue with you in late 1999 and early 2000 on the Transmission Business Line's (TBL) proposed program level expenditures for Fiscal Years (FY) 2002 and 2003.

The TBL Vice Presidents presented the transmission organization's proposed capital, expense, and fiber optic program levels for FY2002-2003 at five regional workshops in November 1999. At your request, two additional workshops were held in Portland in February 2000 so that the Vice Presidents and staff could discuss directly with you the details of the proposed program levels.

In the course of those workshops, the TBL made changes to its spending proposals, while maintaining the program level required to operate a reliable transmission system, and still be responsive to the new challenges of a competitive marketplace.

In the November workshops, the TBL proposed an average annual expense estimate of $334.8 million for the FY2002-2003 period. However, based on our discussions with customers and the TBL's own internal review, our February workshops included an expense estimate that had dropped about $15 million to $319.3 million[1]. Likewise, the TBL's capital program was adjusted downward by $1.2 million to about $246 million[2].

Upward Pressures on Our Spending Levels

In the workshops, we demonstrated how we had significantly reduced both capital and expense spending over the past 5 years. However, we also showed that issues facing the transmission industry, and the TBL in particular, will drive our future costs upward.

1 For details on the final TBL expense estimate, visit the TBL web site at http://www.transmission.bpa.gov/tbllib/newsevnts/docs/novq/proglevelcosts3.ppt.

2 For details on the final capital spending, see http://www.transmission.bpa.gov/tbllib/newsevnts/docs/capitalprogram3_16_00.pdf)

During those 5 years, the TBL controlled its spending through management and efficiency efforts. We cut back significantly on transmission upgrades and expansions, relying on technology, such as shunt capacitors, more remedial action schemes and other low cost fixes, to helps us exploit the existing margin in the transmission system. This technology allowed us to absorb growth while still maintaining reliability, but while doing so we accepted more risk and pushed the system harder. Due to growth and open access, that margin is now gone. The system is near capacity and significant constraints could begin to affect open access to the system. The TBL must look at ways in the coming years to bolster transmission in order to maintain a sufficiently reliable system.

Specific factors that are driving future increases are regional load growth, a heightened and mandated level of transmission reliability, costs of separating the power merchant function from transmission, transfer of generation input costs for Ancillary Services from the Power Business Line to TBL customers, succession planning due to anticipated retirements over the next 5 years, and mandated payments into the Civil Service Retirement account.

Capital and Expense Spending Levels

Comments from customers were extensive, creative, and very helpful to us in finalizing our proposed spending levels for the coming years. Some comments were intended to result in a reduction in planned program costs by either cutting programs or by assigning costs directly to parties who benefit from the planned actions. Others questioned rising costs in certain areas, such as in marketing, facility leasing, the Civil Service Retirement catch-up, and the employee awards program. Others, looking at past budget-to-spending performance, asked that we budget more closely to what we actually spend. The reductions take into account an expected drop in spending for new capacitors due to actions we expect some customers to make to avoid the TBL's Power Factor charge (refer to Appendix 1, where these concerns are addressed in detail).

During the discussion on program levels, several policy issues arose. One focused on who should pay for transmission investments under various construction scenarios. Some comments on this issue had to do with practices already decided by BPA, such as those covered in the TBL's Direct Assignment Guidelines.

Another policy issue asks whether BPA should build for forecasted transmission loads or only for those loads where there is a contractual obligation. In the coming years, we will seek to maintain reliability consistent with historical standards of service. We are also committed to identifying regional reliability issues, proposing solutions, and using all available mechanisms to drive to economic and equitable solutions. BPA will facilitate a broad regional dialogue that results in clearly-defined responsibilities for power suppliers, transmission suppliers, governments, and customers in a deregulated market (refer to Appendix 1 for more details).

<u>Fiber Optic Spending</u>
The Transmission Business Line incorporated your comments from the public meetings into its fiber optic report to Congress. All federal power marketing administrations were required to submit such a report by April. Due to the timing of this mandate, the deadline for commenting on fiber was January 6, so the report could be prepared on time. An additional option has been included in the plan. BPA will now encourage third-party, or joint ownership, of fiber through limited competition for new fiber-optic projects, where such ownership meets the BPA pole attachment criteria (currently under revision) and is the least-cost alternative. The final report as submitted to Congress is enclosed as Appendix 2.

<u>Program Level Closure</u>
The TBL is facing some critical issues as to reliability, succession planning, and compensation, and the TBL capital and expense proposed spending levels for FY2002-2003 reflect its decisions. In turn, those decisions are partially crafted by customer and constituent input. Through this Program Level process, our customers have helped us both to hone our proposed spending and to understand alternatives that are available to us. Once again, the Northwest energy community has come together to help us work through these difficult issues.

We remain committed to these open processes where ideas can flow freely for the region's benefit. Thank you for your participation in the Transmission Business Line's Program Level process.

Sincerely,

J. A. Johansen

Judith A. Johansen
Administrator and Chief Executive Officer

Enclosures:
Appendix 1 – BPA Expense and Capital Spending FY2002-03 Program Level Process report
Appendix 2 – BPA Fiber-Optic Cable plan
Map of Fiber-Optic and Transmission Routes

APPENDIX 1

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION BUSINESS LINE
EXPENSE AND CAPITAL PROGRAM
FISCAL YEARS 2002 and 2003
PROGRAM LEVEL PUBLIC PROCESS

BONNEVILLE
POWER ADMINISTRATION

May 26, 2000

I. Marketing and Sales Expense

Some customers said they do not understand the need for an extensive "Marketing and Sales" function given the essentially monopolistic character of the Transmission Business Line (TBL) system. Further, they said that to balance the rising costs in the Scheduling area, costs should be reduced in other areas within Marketing and Sales. But some customers also question the increase in costs in the Scheduling function, which appear to be based on the assumption that the TBL will move to ten-minute schedules.

The Public Generating Pool (PGP) said that, given the repeated observation that TBL is having difficulty managing the number of schedules and in light of the dramatic increases in the past few years, building a scheduling function on the assumption that the number of schedules will increase from 2,500 per day to 15,000 per day seems unrealistic.

The Marketing and Sales function includes the following responsibilities:

Marketing - VP, Account Executives, and senior experts
Billing - Prepares over 200 transmission bills each month
Contracting - Contract development and administration
Finance - Budgeting and accounting for all of TBL
Strategy - Business planning, revenue forecasting and rate development
Scheduling - Pre-schedule, reservations, real-time, after-the-fact, and technical support

While on the surface it may seem unnecessary for a "transmission monopoly" to have a marketing and sales function, the TBL marketing organization serves as the front line in managing customer relationships for what is currently a $550 million/year business. The California Independent System Operator (CA ISO) also has similar functions.

As noted in the table on page 11 of the materials posted on January 21, 2000, the Marketing function also captures all of the legal expenses directly charged to the TBL. Included in Fiscal Year (FY) 2000 are extraordinary expenses associated with dispute resolution and litigation.

Approximately 30 percent of Marketing expenses are attributed to scheduling. This area grew significantly from FY1997 through FY1999 as TBL and PBL functionally separated. A key driver is wholesale competition, which increased the number of schedules from 200 per day to approximately 2,500 per day. Additional workload came from seven day scheduling to conform with the CA ISO. Customers continue to demand better outage coordination and greater flexibility. TBL provides significant resources to Northwest and WSCC scheduling coordination efforts. All of these factors have led to current staffing levels.

New pressures include the North American Electric Reliability Council (NERC) mandated Electronic Tagging and the potential for 10-minute schedules for the Energy Imbalance market in the CA ISO, although BPA is not currently anticipating a six-fold increase in the overall number of schedules as mentioned in the comments. TBL is investing in a modern E-tagging and scheduling system to manage the increased requirements and workload as efficiently as possible.

Other than Scheduling and Legal expenses, Marketing and Sales experienced only modest spending increases since FY1997. Projections for years FY2001-2003 are each lower than in FY2000. Based on the above, we conclude that the Marketing and Sales expense spending is appropriate as described in the January 2000 presentation materials.

II. Employee Award Program

Customers were concerned about the increases projected for employee bonuses in FY2002-2003. TBL projects $9.25 million/year for employee bonuses. This is well above historic budgeted levels of approximately $5.1 million/year for FY1997-2001.

Moreover, TBL estimates that actual amounts paid were one-half of budgeted amounts because not all employees qualify for the bonus. Some customers suggested it would be more realistic for TBL to budget employee awards according to expected expenditures based on past pay-outs, not on the maximum amount that could be paid to employees if all goals are met.

In a move to operate in a more business-like manner, BPA expanded its agency-wide Recognition Plan beginning in FY2000 to provide greater incentives for high performing employees. The program has three major components: BPA Success Share, Organizational Team Share (e.g. TBL) and Individual Awards. In FY2000, 8.25 percent of base salary is in the recognition pool, increasing to 10.0 percent in FY2001 and beyond. Of these amounts, 1.0 percent in FY2000 and 1.5 percent in FY2001 and beyond are not budgeted, but only become available if the Net Operating Margin financial target is exceeded by twice the amount needed to fund the expanded pool.

The first two components are based on meeting financial and other performance targets set early in the fiscal year. The business line financial targets (Cost Structure, Net Operating Margin and Capital Spending) are developed in coordination with Corporate to achieve financial objectives, such as managing program growth. The non-financial targets (e.g. reliability and safety) are derived from industry standard approaches where available. Pay-out from the pool is in proportion to the number of targets met, so that the full amount is at risk. The table below shows the number of targets met divided by the total number of targets for the past three years (TBL Team Share was implemented in FY1999).

	BPA Success Share	TBL Team Share
FY97	6/6	N/A
FY98	5/6	N/A
FY99	6.75/9	16.5/18

Individual Awards are the more traditional part of the BPA Recognition Plan based on specific achievements. They include components such as On-the-Spot, Individual Results, Team, Safety, and Time-off awards. Most TBL organizations award more than 90 percent of the available pool.

When BPA first presented the program levels at a Rates Workshop in October 1999, budget for awards was $1.5 million/year higher to allow for further growth. Based on feedback, we reduced the projected awards to an average of $9.25 million/year in November. Given the newness of the expanded awards program and the non-funded portion noted above, it is appropriate that the projected amount not be further reduced.

III. CSRS Payback

Customers suggested that the deferred obligation to the CSRS should be phased in over time, rather than front-loaded into the FY2002-2003 period. An agreement between the Office of Management and Budget and BPA's Administrator allowed BPA to defer a portion of its annual non-funded obligation for CSRS and post-retirement health benefits until after the current rate period. The agreement defined the payment schedule over a 10-year period. The payments for the first 4 years (the years of the current rate period) ramped up from 10 percent of BPA's annual non-funded obligation to 40 percent. In years 5 and 6, the agreement called for BPA to pay 60 percent of the annual non-funded obligation plus the prior years' remaining balances with interest. This percent ramped up each year by 10 percent until it reached 100 percent in the 10th year.

IV. Facility Leases

This program is titled "Transmission Facility Leases", because most of the expenses included in this account are for "Transmission Facility Leases" or other customer cost sharing arrangements that support the transmission system. However, the program does include costs for other system support activities such as Western States Coordinating Council dues, planning, system studies, computer-aided design and the geographical information system. In FY1997, the $2.2 million dollars shown as an expense represented these other system support activities and did not include facility leases. The expenses for facility leases were not assigned to the TBL until FY1998. This is why the costs shown in our presentation rise from $2.2 million in FY1997 to $8.3 million in FY1998. The costs were higher again FY1999 due to new facility leases.

In addition to inflation, staff also forecast increases for known new lease and customer cost sharing arrangements that resulted in the FY2000 forecast of $14.8 to the FY2003 forecast of $17.9 million. We also expect that most of the existing leases will be extended even though many of these leases are expiring in 2001. Based on current agreements, known TSD program increases include $3 million for new leases, $2 million for customer cost-sharing arrangements. We also expect increased cost pressures of $1-2 million for system planning and studies due Regional Transmission Organization (RTO) and reliability issues.

V. Overhead Expenses

Customers were concerned about TBL overheads, including the significant portion of BPA corporate overheads TBL continues to bear. Among others, these overheads consist of such expenses as shared services, general and administrative and support services. Coupled with their concern about the amount of overheads is whether they stand up to the test of competing with outsourced services. This becomes especially important, they said, as TBL moves further toward separation from BPA's merchant function and closer to participation in an RTO.

As BPA shifts costs from corporate to shared services, TBL will be able to better compare those costs for services with other outsourced services. Regardless of how corporate comes out in that competition, TBL continues to be committed to reducing all expenses where possible.

TBL's expenses can be classified as direct (e.g. lineman or electrician wages and benefits), factory overhead, and non-factory overhead. Transmission factory overhead includes all costs (in addition to direct costs) necessary to produce a product or service. Non-factory overhead, which is sometimes referred to as general and administrative (costs), are those costs that benefit the TBL as a whole, but are not necessarily always perceived as directly benefiting individual segments of the TBL, but is a full partner with the success of TBL.

The following analysis (second chart) identifies those expenses that can be identified primarily as "non-factory" overhead. These expenses include corporate and executive level operations, such as executive management, legal, sales, accounting and personnel. Overall, TBL non-factory overhead declined from the 1997 through the 2003 forecast when compared to total expenses, even though TBL incurred additional costs due to separation (e.g. TBL finance, executive salaries, legal, marketing, etc.).

The Corporate costs shown below for FY2002-2003 are consistent with the recommendations made by the Cost Review Panel. The Shared Service costs are based on current costs trended to be consistent with the Cost Review Panel recommendation.

Expenses Presented in the meetings on Reliability and the Future of Transmission Costs

Description	FY97 Actual	FY98 Actual	FY99 Actual	FY00 Forecast	FY01 Forecast	FY02 Forecast	FY03 Forecast
System Maintenance	$59.2	$61.3	$64.1	$67.3	$69.1	$71.3	$73.4
System Operations	23.2	24.9	27.3	29.2	31.1	37.0	38.1
System Development	5.3	9.6	11.5	16.0	19.4	26.2	27.3
Marketing & Sales	8.6	11.2	13.5	17.7	15.5	15.2	15.7
Environment	6.5	5.6	5.4	5.0	5.0	5.1	5.3
Support Services	9.3	4.8	10.0	12.7	12.5	11.9	12.2
Transmission G&A	17.5	20.1	13.7	18.7	21.1	22.2	23.8
Corporate & Shared Services	36.0	35.2	31.0	36.0	34.3	30.0	28.1
Between Business Lines	10.7	41.3	39.5	37.9	38.9	84.3	84.3
CSRS	0.0	1.1	2.1	3.0	4.0	27.6	17.6
Total Operating Expenses	$176.3	$215.1	$218.1	$243.5	$250.9	$330.8	$325.8

"Non-Factory Overhead included in expenses shown above

R&D and EPRI - System Operations	$1.4	$0.7	$1.0	$1.2	$1.5	$1.5	$1.6
Marketing - Marketing & Sales	1.8	2.1	2.3	3.5	2.6	2.5	2.6
Finance - Marketing & Sales	0.4	0.6	0.6	0.8	0.8	0.8	0.8
Strategy - Marketing & Sales	1.9	1.7	1.9	2.0	2.4	2.3	2.4
Legal Support - Marketing & Sales			1.6	2.6	1.3	1.3	1.3
Fixed Wing Services - Support Services	0.3	0.3	0.4	0.3	0.3	0.3	0.3
Support Services - Support Services			1.6	2.0	2.0	1.9	1.9
Information Resources - Support Services			4.4	6.0	5.9	5.6	5.8
Other Support Services - Support Services		0.4					
Executive Management - Transmission G&A	1.1	1.5	2.1	1.7	1.5	1.4	1.6
General Administration - Transmission G&A	0.5	0.7	1.0	1.9	2.3	2.2	2.5
Office Moves & Leases - Transmission G&A	2.9	1.5	-0.2	0.2	0.1	0.5	0.5
Support Services - Transmission G&A	0.7	1.1					
Information Resources - Transmission G&A	3.9	4.9					
Corporate Field Services - Transmission G&A	1.1	1.1	1.1				
Corporate	27.7	25.8	27.2	24.3	22.6	8.5	8.1
Shared Services	8.3	9.4	3.8	11.7	11.7	21.5	20.0
Total Non-Factory Overhead	$52.0	$51.8	$48.8	$58.2	$55.0	$50.3	$49.4
Non-Factory Overhead/Total Operating Expenses	29.5%	24.1%	22.4%	23.9%	21.9%	15.2%	15.2%

VI. Transmission System Development

Congestion Management
Construction due to fish spill
Reactive Costs

Many customers suggested that TBL relieve transmission congestion through redispatch protocols and not include as much transmission construction in the budget. TBL believes that a transmission provider needs to employ both methods to ensure an appropriate balance of costs and maintaining reliability.

Generation redispatch is one viable, although potentially costly, method of managing congestion. It will likely be successful when the level and the number of hours of congestion is small. However, there are some cases when redispatch won't solve a congestion problem. Some constrained paths where the congestion problems are larger than redispatch can solve are West of McNary and the Idaho path. In addition, where insufficient generation exists to provide adequate voltage support, redispatch won't help. That is the situation in some areas due to a recent agreement with the National Marine Fisheries Service (NMFS) to provide additional juvenile salmon in their migration to the ocean. In addition, where insufficient generation exists in a load area, such as portions of the I-5 corridor, redispatch won't help and load curtailment will be required. In these situations, the solutions might include transmission, local area conservation, DSM or generation.

Changes to Lower Snake and Columbia River operations due to spill were not discussed at the Program Level public meetings, but they will result in a need to accelerate some construction projects and to reinforce other areas that were not discussed at those meetings. See the full discussion of those projects below.

On the other hand, construction at the Northern interconnection may be deferred and that money may go to pay for projects required due to fish spill. In addition, TBL is now assuming that due to higher reactive charges, more utilities will begin to supply their own reactive, allowing TBL to reduce this budget item by $1.2 million.

DISCUSSION

Most transmission reinforcements over the past 15 years have involved the outer edges of the Northwest transmission system. Those projects included the Northern interconnection, integration of the Colstrip generation, the 3rd AC Intertie, and the DC upgrade. All can be considered the 'limbs' of the system. Now, Intertie transfer capabilities have increased significantly, resulting in higher internal grid stress. During that time period, relatively few additions have been added to the NW grid (the 'torso').

At the same time, loads over the 15-year period have grown by nearly 35 percent -- much on the west side -- and transmission customers have increased pressures to maximize transmission availability and predictability. The current situation is:

- The transmission system is at or near limits. Workload to manage the system goes up as system stress increases.
- TBL is reaching the limits of capacity provided by extensive remedial action measures.
- Reliability criteria changes are reducing capacity from where TBL is now all over the west. This is likely to increase as entities move into compliance with WSCC and NERC criteria.
- Curtailments are happening more often.
- Planned outages are more difficult to arrange.
- The market wants more certainty and lead-time about transmission availability.

Although PGP suggested that redispatch could replace the internal path reinforcements in TBL's budget to gain congestion relief, given growth and the stress on the system, redispatch simply cannot provide full congestion relief. Construction is needed to solve reliability criteria violations that redispatch cannot fully resolve.

<u>Reinforcements for fish spill</u>
Uncertainties in capital requirements that could raise costs were outlined in the program review, but TBL did not identify their costs. They include reinforcements needed for additional changes to river operations for spill or breach.

River operating agencies -- BPA, the Bureau of Reclamation and the U.S. Army Corps of Engineers -- agreed with NMFS in early April to a spill regime for at least the next 2 years. That regime will be included in NMFS' 2000 biological opinion to protect endangered salmon and steelhead in the Federal Columbia River Power System. That agreement requires additional spill on the Lower Snake and Columbia rivers. The result is a need to accelerate some north-south transmission construction between Ellensburg and the Tri-Cities in Washington (Schultz-Hanford 500-kV line) and put more importance on the West of Hatwai improvements that are already in the budget. The new Schultz-Hanford line is estimated to cost about $54 million and be energized in 2004 or 2005. This expenditure will have to fit into the total spending amount discussed in the public meetings.

Other constrained paths

- West of McNary improvements are needed to move new firm generation and other transfers through the McNary area.

- The Idaho path improvements are needed to meet the firm transfer requirements for the growing loads in southern Idaho. The need for these two projects is unchanged.

- There have been some changes in requests to interconnect generation in the Bellingham area. Consequently, the Northern interconnection project may be deferred.

- The Schultz-Hanford project funding may come from the money programmed for the Northern interconnection improvements and other contingency funds.

Reactive Costs
TBL initially projected $5 million per year for reactive capital investments. This was based on historic levels of spending for these types of investments. However, this level was set independently from the expected impact of the proposed higher reactive charge. As some customers pointed out, it is reasonable to assume that the higher charge for transmission supplied reactive would result in retail utilities supplying more of their own reactive needs and reducing the need for TBL to supply additional VARS. To take this into account, TBL reduced this projected amount item by $1.2 million to $3.8 million per year.

VI. REPLACEMENT PROGRAM CAPITAL SPENDING

BPA received comments that actual spending on replacements has been historically lower than its budget by an average of about $15 million per year. Some suggested TBL should reduce, across the board, its proposed FY2002-03 replacement spending by that $15 million in order to reduce the revenue requirement in the rate case.

The actual budget deviation over the past five years has been $13.36 million per year. Several things are occurring:

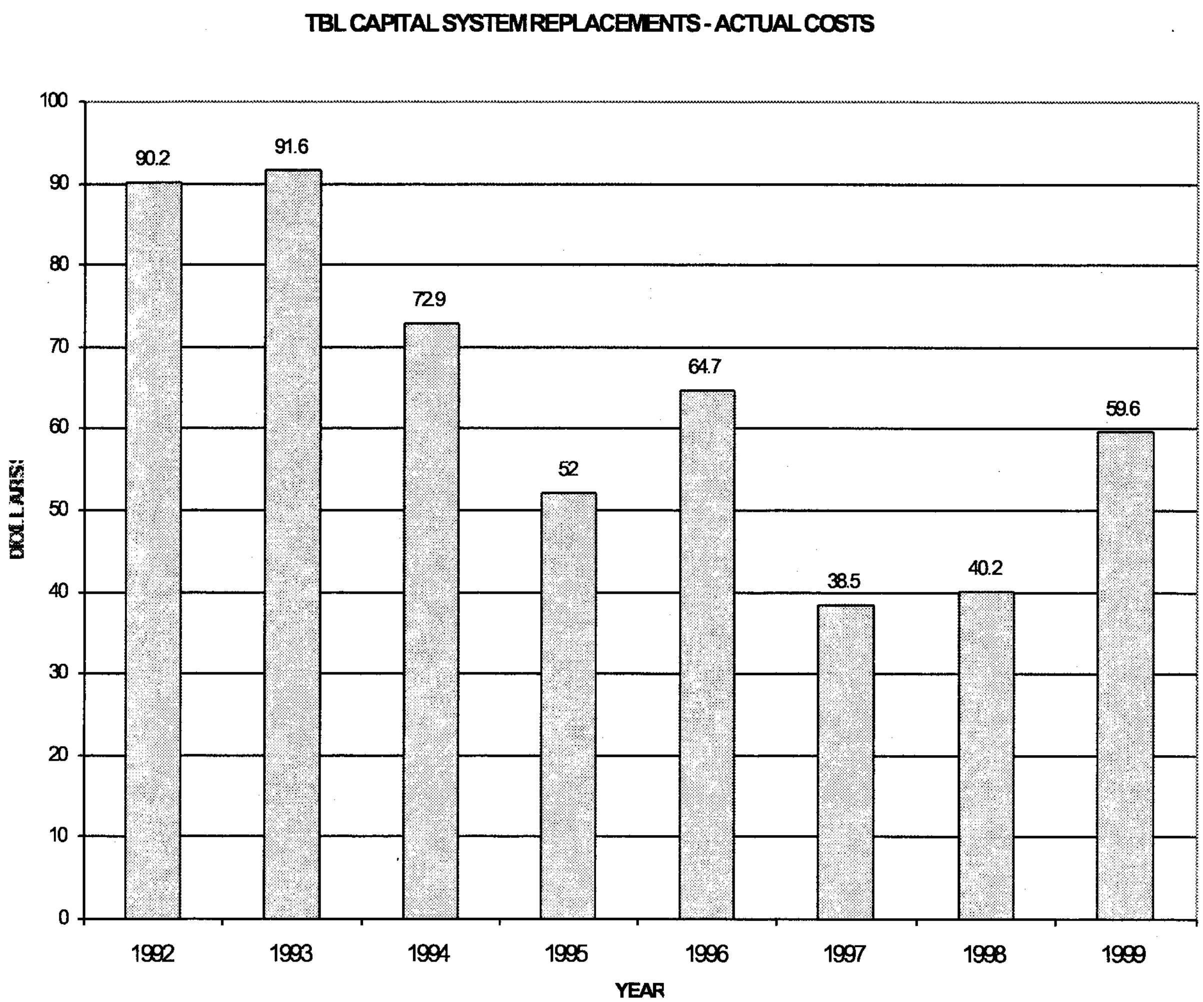
- First, TBL made a conscious effort to keep expenses under budget (see History, below) and it will continue to look for ways to operate efficiently and under budget.

- Second, when the deviation is applied to the rate case, the actual rate requirement is only $500,000 per year, or about one-tenth of one percent of the proposed rate case. That's well within TBL's estimating capability.

- Third, some of the replacement budget includes items that help TBL deal with risk. In its budgeting process, TBL attempts to balance cost-cutting in maintenance and replacement programs with the risk of weather or equipment-driven outages.

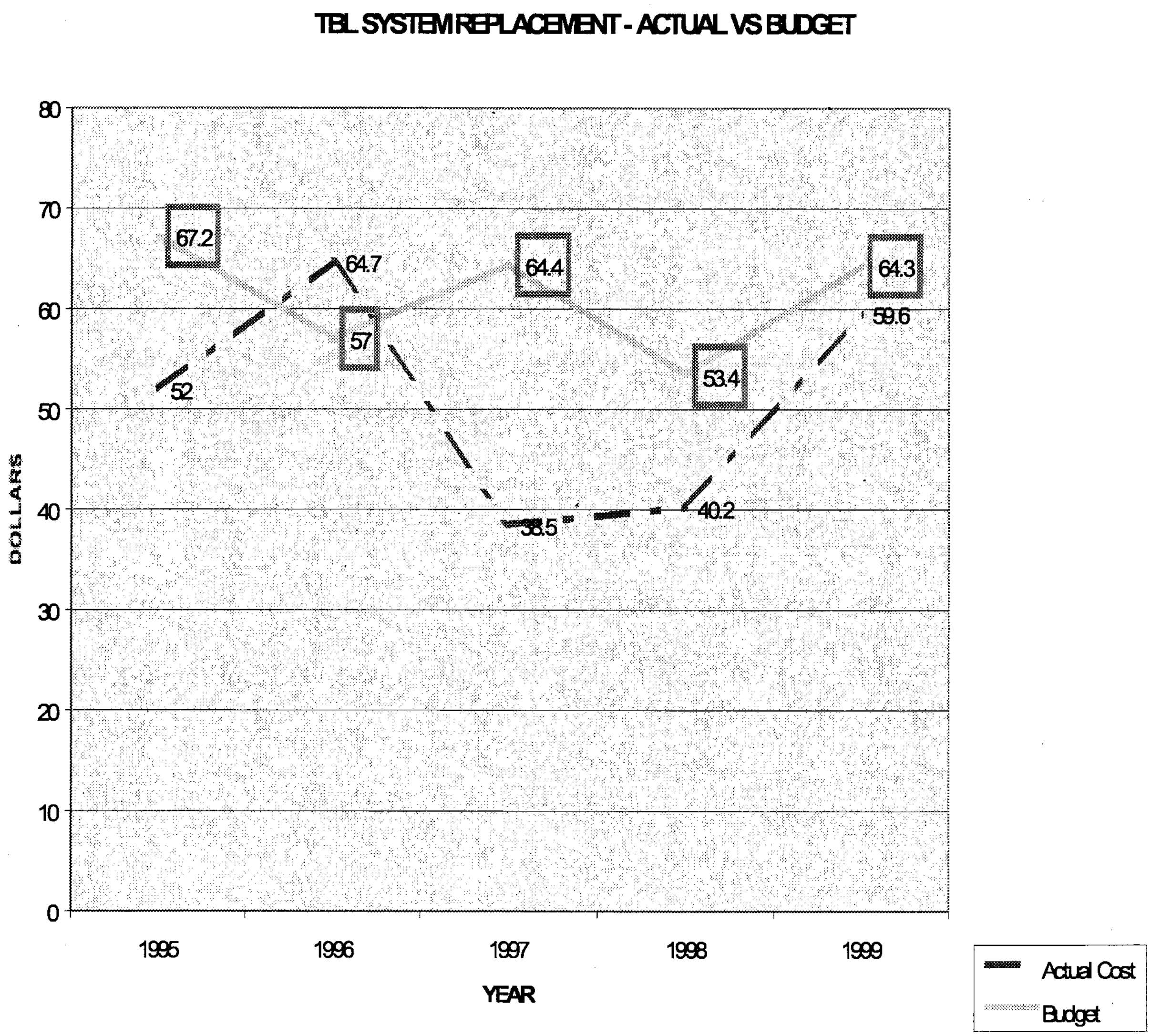
A HISTORY OF REDUCING COSTS

The TBL has consciously reduced its spending on replacement items. It reached a low of $38.5 million in FY1997, which is down some 68 percent from a 1993 high of $91.6 million (see graph below). These reductions resulted from limits to TBL's borrowing authority, a reduction in maintenance and construction resources, and the adoption of a Reliability-Centered Maintenance (RCM) program. These reductions were accomplished even though planned equipment outages were down due to capacity and reliability restrictions. The harder the system is driven, the more susceptable it is to the risk of failure. Yet, to the greatest extent possible, the savings were achieved with relatively small interruptions in continuous customer service.
One of our great success stories has been to find cost-savings to help preserve our borrowing authority, and at the same time, meeting customer needs for reliable service.



The RCM program philosophy has moved the organization away from a time-based maintenance and replacement approach and toward a needs-based program. RCM is based on equipment diagnostics and testing. Its costs are not as easily forecast as were those of the preventive maintenance program in which replacements were made on the basis of time in service, rather than need. However, it is the most cost-effective approach and it achieves a high reliability.

The projected replacement spending also contains a contingency for major equipment failures and storm damage, both of which are difficult to forecast. However, those items allow TBL to plan for a modicum of risk in its budget. There also have been a number of cases where material and resources designated for the replacement program had been redeployed to emergency or reliability related projects. Two of examples of unplanned spending were an $8 million transformer failure, and line damage due to an ice storm costing $1.6 million.



The actual verses budget deviation anomaly in 1996 (see graph above) was a conscious decision. It was recommended by the Regional Review to reduce capital spending to extend TBL's borrowing authority.

FY2002-03 SPENDING LEVEL DRIVERS

However, for the next rate period, FY2002-2003, TBL is faced with additional replacement costs due to aging of the equipment - a result of trying to stretch out its useful life - and a deferral of maintenance during the current rate period. Some of the spending level drivers on which the FY2002-2003 spending estimate is based includes:

- 15,000 wood poles that exceed 60 years of age. Tests indicate a degradation of up to 50 percent of rated strength.
- Congressional sales of Federal communication frequencies will force TBL to replace many of its command and control systems.
- Substation high voltage equipment continues to age, yet TBL is continually pressured to increase loading on that equipment.
- Many buildings and substation facilities are in excess of sixty years of age. Some investment in infrastructure is unavoidable.
- The process of separating Business Lines will continue to require upgrades or replacements of business systems; such as metering, billing and scheduling systems.
- The replacement of leased facilities will reduce long-term expense costs and assist in the effort to keep rates down.

VII. Who Pays Construction Costs

BPA received a number of customer comments asking whether it should pay for the total cost of all construction projects, or in some cases would those costs more properly be paid or shared by others. Generally, the comments addressed five types of construction projects:

- Reliability driven projects
- Non reliability projects
- Generation integration projects
- Area service projects
- Projects that enable wheeling through the BPA network

TBL's Matrix Team is an internal group that looks at each capital project against a set of financial and non-financial criteria. One factor is whether the project generates sufficient revenue to cover the project cost, whether through rates, incremental pricing, co-funding, or other arrangements as determined by the policies described below. In addition, all projects undergo some type of NEPA process, which allows for public review of the need and appropriateness of the solution.

TBL also must consider Federal Energy Regulatory Commission (FERC) direct assignment policy which governs whether construction benefits all customers and costs should be assigned to the Network or if it is for the benefit of individual customers.

Reliability Driven Project

TBL has built the backbone of the Northwest's high-voltage grid. Other utilities own transmission, in some cases, quite a lot. However, within the region, TBL owns about 80 percent. TBL has always felt responsible for keeping the lights on and has worked for a high standard dictated by the NERC, by the WSCC, and by its own reliability criteria. But transmission is only one-half of the equation. Generation needs to be available when high loads stress the system. Yet, little new generation is being added in the Northwest now, though some is on the drawing board. The transfer capability of the interties with other regions is several thousand megawatts short of the imports that would be needed by 2003 to keep the lights on if a severe cold snap occurred in a drought year. BPA's Power Business Line could probably meet its own loads by importing energy from outside the region and by drawing down reservoirs and replenishing them later to meet fish flow requirements. However, other regional power suppliers appear to be significantly short of power, and the PBL would be competing heavily for the limited import capacity. There's just not enough to go around.

This is not just a problem for the Northwest. It's happening all over the nation as utilities try to position themselves for restructuring. BPA is commissioning a two-part response to this reliability challenge:

1. BPA will facilitate a broad regional dialogue that results in clearly defined responsibilities for power suppliers, transmission suppliers, governments and customers in a deregulated market.
2. In the interim, BPA will seek to maintain reliability consistent with historical standards of service through:
    a. maintaining, operating and building its transmission grid and purchasing generation as needed to meet its responsibilities, and
    b. identifying regional reliability issues, proposing solutions and using all available mechanisms to drive to economic and equitable solutions.

Non-Reliability Projects

The TBL projected spending levels include approximately $103 million in capital spending for FY2002-2003 to increase ratings on four internally-constrained paths. That is about one-fifth of the total capital spending for these 2 years. Improvements are planned for West of Hatwai, West of McNary, and PNW-Idaho. Spending for the Northern interconnection project, which was initially proposed in the spending estimates, may be deferred and the money may be used to relieve congestion resulting from additional spill for fish (see the response on congestion management).

Not all customers disagreed with TBL's proposal. Some, in fact, were encouraged by plans to relieve congested paths into the Northwest and believed it fit TBL's mission to pay for those investments. PBL said, "By TBL reinforcing access to outside energy markets, there should be increased pressure for market competition to occur. TBL would be promoting efficient and non-discriminatory power markets to evolve."

Other customers recommended TBL preserve or delay capital spending by treating congestion with redispatch or other non-construction means. The Public Power Council asked, "Why not explore economic congestion management or other methods that may be cheaper solutions to the problem? PPC supports near-term transmission investments needed to maintain reliability, but questions whether investments intended to facilitate commercial transactions are clearly BPA's responsibility."

As is indicated in the response on congestion management, TBL is considering redispatch as a way of controlling congestion. However, redispatch is often not sufficient to relieve the problem. In those situations, TBL must also proceed with transmission construction to relieve congestion. Successful power delivery requires both methods.

TBL is clearly responsible to manage congestion. While doing that, its policy is to ensure that sufficient revenue is generated by path reinforcements to justify the cost of transmission construction. In fact, one of the key functions of the TBL Matrix team is to review the feasibility of path reinforcement projects.

<u>Generation Integration</u>
Some customers questioned how much of TBL's planned investments should be assigned to newly-sited generators and how much should be assumed by TBL.

PGP expressed concern about the West of McNary reinforcement, for which TBL has programmed about $10 million. "...[T]he West of McNary path has difficulties associated with new generation in Hermiston. Why were these difficulties not identified in the System Impact Studies and appropriate costs assigned to the new generation?"

The West of McNary path is part of the main grid network used by generation at Hermiston. It is also used for power flowing from other east side resources and transfers from Idaho. The upgraded facilities, then, would also benefit the Network and not just the new generators. FERC regulations are clear on who pays for Network additions: wheeling customers should pay the greater of incremental or average costs, but not both. In this case, the incremental cost of these facilities is less than the wheeling rate.

Area Service Projects
The TBL proposed spending levels include approximately $64 million for Area Service Projects. Some customers questioned whether BPA should pay for all these investments, whether specific customers should pay for these projects, or whether TBL should seek cost-sharing arrangements.

Seattle City Light suggested that "TBL should explore the potential for creative opportunities such as offering joint public or private ownership of proposed investments in new transmission."

PGP provided a way of delineating who should pay: "We question whether these investments truly provide improvements to "network" service, as opposed to meeting the legitimate needs of only some customers in the region."

TBL reviews all projects on a case by case basis. It is TBL's policy to construct facilities when they provide general network benefits or where TBL has an existing contractual obligation. Following its direct assignment guidelines, TBL is willing to pay for that part of a project that benefits multiple customers. However, as a general rule, TBL avoids constructing facilities for exclusive use by individual customers except on a reimbursable basis. If a facility is being built for a single utility, that utility would generally pay the project's cost.

Many TBL customers are Network Service customers. Generally, NT contracts obligate TBL to provide facilities that meet new load growth. If that requires additional Network transmission facilities, TBL will generally pay for the project.

At the same time, TBL is open to working with others who benefit from projects or exploring partnerships with others to help solve mutual problems. TBL, then, does make an effort to work out joint funding of projects. In the case of the Kitsap project proposed for FY2002-2003, the joint project with Puget Sound Energy entails TBL upgrades to its facilities and PSE upgrading its facilities to complete a mutually beneficial project.

In a different type of arrangement this year, TBL is completing Swan Valley-Teton line upgrade project in which the utility is responsible for half the cost until the load reaches a certain size.

As mentioned earlier, the FERC direct assignment policy governs this review. TBL has described its application of FERC policy in it's "Guidelines for Direct Assignment Facilities," which was developed through a public process. The guidelines are available on TBL's web site (http://www.transmission.bpa.gov/busprocess/dafacility.htm).

In addition, TBL is in the process of divesting itself of delivery facilities to the greatest extent practicable.

Projects that Enable Wheeling Through the BPA Network

Some of TBL's proposed construction projects are to meet the growing demand for transmission service for utilities outside the region who wish to wheel power from or across the Northwest to markets in California or the Southwest.

Some customers believe that BPA should reinforce only those facilities designed to improve reliability for Northwest loads. Snohomish County PUD said, "At a minimum, if transmission upgrades are proposed primarily to benefit out-of-region wheeling customers, the cost of those upgrades should be borne by those out-of-region customers."

Under FERC rules, TBL is required to provide wheeling paths to all types of customers without discrimination. TBL works to equitably divide the cost for service to customers who benefit through its wheeling rates. For example, BPA has a separate Southern Intertie segment. Only users of that segment pay the costs. As with all other capital projects, before funds are obligated to reinforce a wheeling path, proposed projects are brought before the TBL Matrix Team for review and approval. One of the criteria applied by the Matrix Team is to ensure sufficient revenue is generated by the project to justify the cost. If it does not, other arrangements are made or the project does not go forward.

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