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

BP-16 Initial Rate Proposal

Transmission Revenue Requirement Study

BP-16-E-BPA-08

December 2014

TRANSMISSION REVENUE REQUIREMENT STUDY

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
AER step	Actual Energy Regulation study
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPA-P	Bonneville Power Administration – Power
BPA-T	Bonneville Power Administration – Transmission
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DOP	Detailed Operating Plan
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.

EPP	Environmentally Preferred Power
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services (rate)
FY	fiscal year (October through September)
G&A	general & administrative
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GMS	Generation Management Service
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
JOE	Joint Operating Entity
kcfs	thousand cubic feet per second
kW	kilowatt (1000 watts)
kWh	kilowatthour
LPP	Large Project Program
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPTAC	Large Project Targeted Adjustment Charge
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)

MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power (rate)
NRFS	New Resource Flattening Service
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OPER step	operational study
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people’s utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate

Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

Figure 1: Transmission Revenue Requirement Process

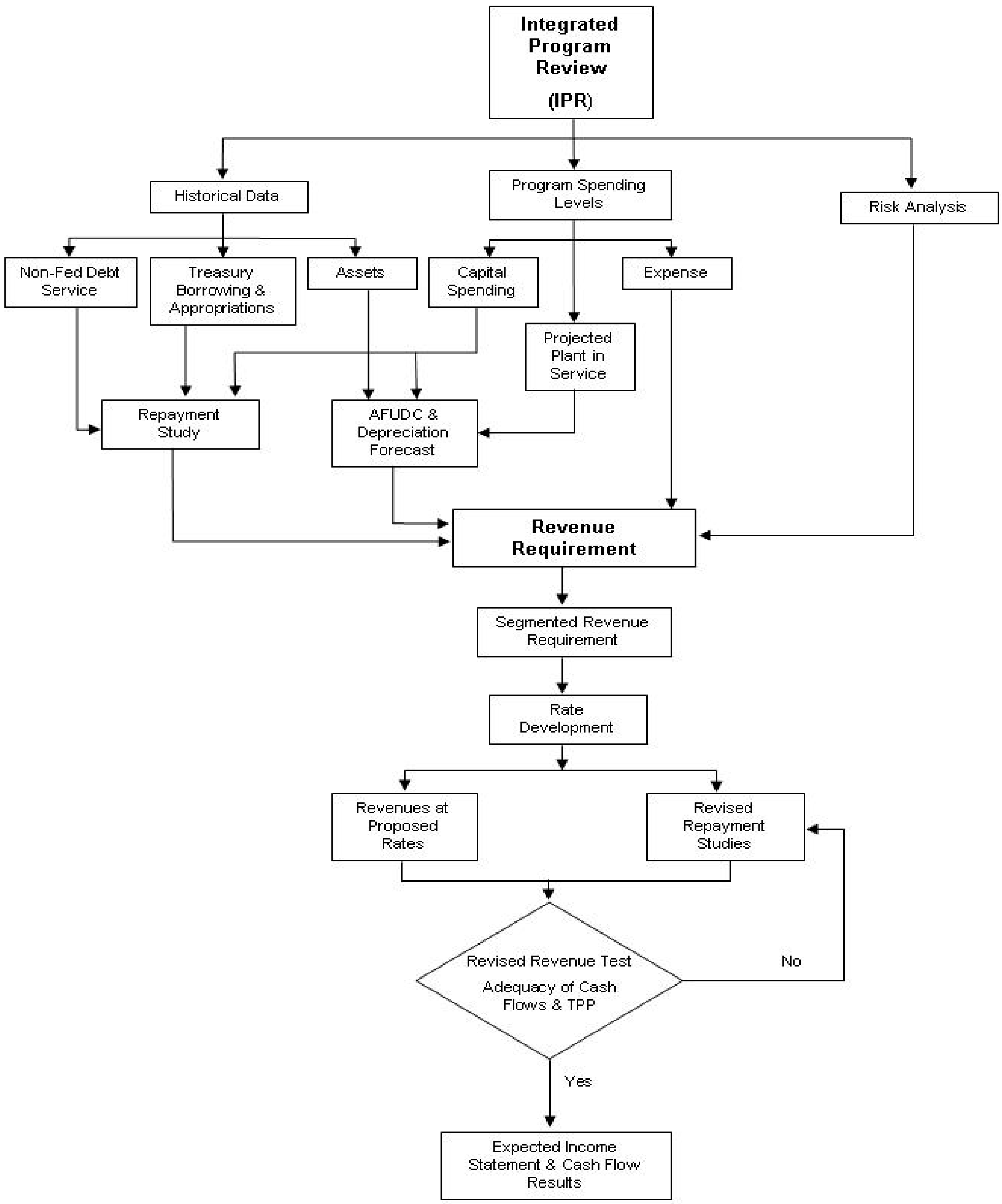
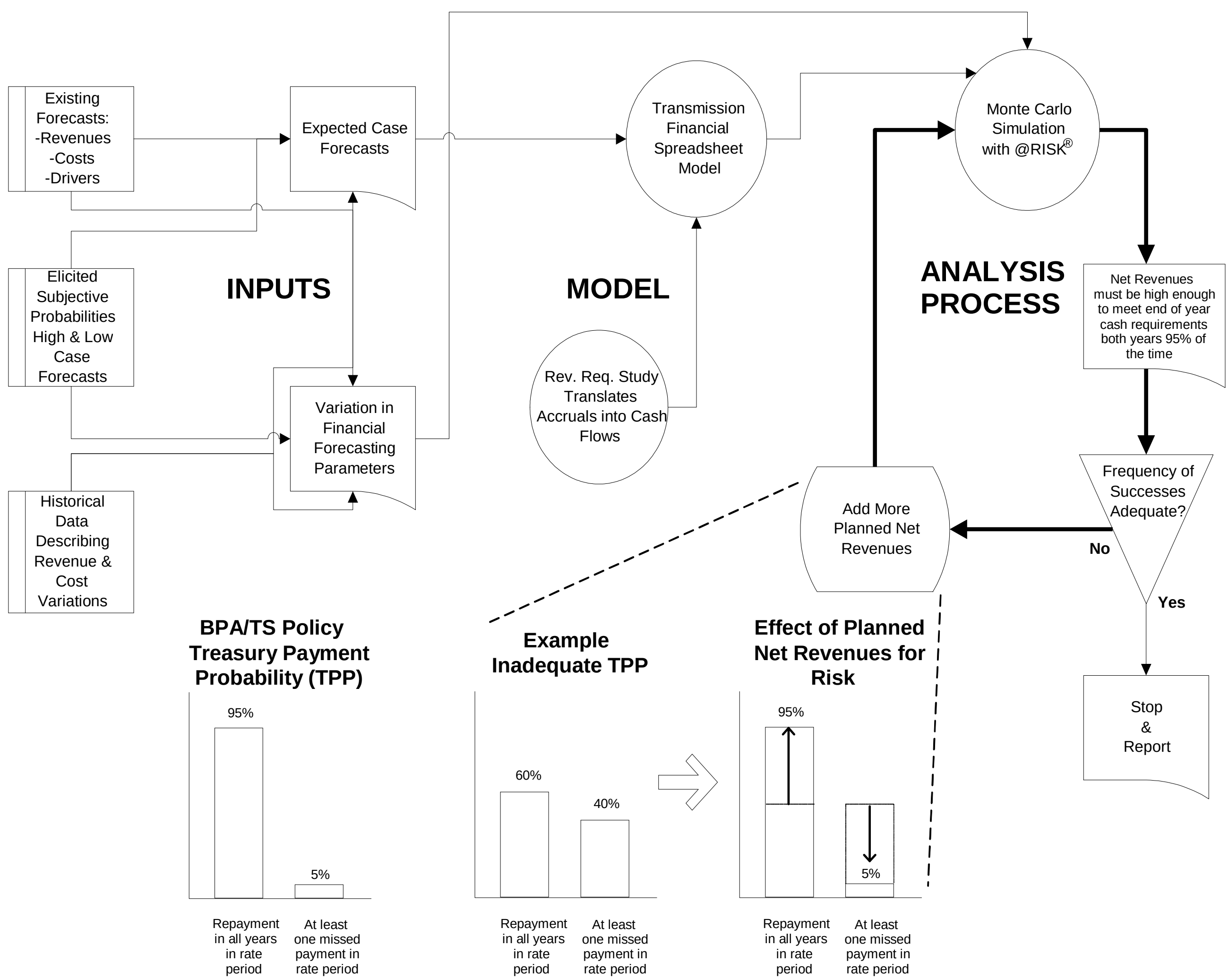


Figure 2: Transmission Rate Case Risk Analysis Flow Diagram



1. INTRODUCTION

1.1 Purpose of the Study

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

The cost evaluation period, as defined by the Federal Energy Regulatory Commission (Commission), is the period extending from the last year for which historical information is available through the proposed rate period. The cost evaluation period for this rate filing includes Fiscal Year (FY) 2015 and the proposed rate period, FY 2016–2017. This study is based on transmission revenue requirements that include the results of transmission repayment studies. This study does not include the revenue requirement or a cost recovery demonstration for Bonneville Power Administration's (BPA) power function. *See* Power Revenue Requirement Study, BP-16-E-BPA-02.

This study outlines the policies, forecasts, assumptions, and calculations used to determine the transmission revenue requirement. The Transmission Revenue Requirement Study Documentation, BP-16-E-BPA-08A, contains key technical assumptions and calculations, the results of the transmission repayment studies, and further explanation of the repayment program and its outputs.

The revenue requirement for this study is developed using a cost accounting analysis comprised of three parts. First, repayment studies for the transmission function are prepared to determine the schedule of amortization payments 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 period and extend over the 35-year repayment period. Second, transmission operating expenses and Minimum Required Net Revenue (MRNR) are projected for each year of the rate period. Third, annual Planned Net Revenues for Risk (PNRR) are determined after taking into account risks, BPA's cost recovery goals, and other risk mitigation measures, as described in this study. From these three steps, the revenue requirement is set at the revenue level necessary to fulfill cost recovery requirements and objectives. This process is depicted in figure 1, above. Once the revenue requirement is completed, it is segmented and passed to the rate development process, where it is used to develop rates in the Transmission Rates Study and Documentation.

Consistent with Department of Energy (DOE) Order RA 6120.2 and the standards applied by the Commission on review of BPA's rates, BPA must determine the adequacy of both current and proposed rates to recover the revenue requirement. BPA conducts a current revenue test to determine whether revenues projected from current rates meet cost recovery requirements for the rate period and the repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements are met, current rates could be extended through the proposed rate approval period. The current revenue test, described in section 3.2 of this study, demonstrates that revenues from current rates will not recover the transmission revenue requirement for the rate period.

The revised revenue test, which is performed after calculation of the proposed transmission rates, determines whether projected revenues from proposed rates meet cost recovery requirements for the rate test and repayment periods. The revised revenue test, section 3.3 of this study, demonstrates that revenues from the proposed transmission rates will recover transmission costs in the rate period and over the ensuing 35-year repayment period. In addition, revenues from the proposed rates, together with risk mitigation tools, are sufficient to meet BPA's 95 percent Treasury Payment Probability standard that all U.S. Treasury payments will be paid on time and in full, as discussed in section 2.2.

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed transmission rates for FY 2016–2017. These net revenues are the lowest level sufficient to achieve, in combination with other risk mitigation tools, BPA's cost recovery objectives in the face of transmission-related risks.

Table 2 shows planned transmission amortization payments to the U.S. Treasury for each year of the rate period.

1.2 Legal Requirements

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

1.2.1 Governing Authorities

BPA's revenue requirements are governed primarily by four legislative acts: the Bonneville Project Act of 1937, Pub. L. No. 75-329, 50 Stat. 731, amended 1977; the Flood Control Act of 1944, Pub. L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River Transmission System Act of 1974 (Transmission System Act), Pub. L. No. 93-454, 88 Stat. 1376, amended 1977; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), Pub. L. No. 96-501, 94 Stat. 2697. The Omnibus Consolidated Rescissions and Appropriations Act of 1996, Pub. L. No. 104-134, 110 Stat. 1321, also guides the development of BPA's revenue requirements.

Department of Energy Order "Power Marketing Administration Financial Reporting," RA 6120.2, issued by the Secretary of Energy, provides guidance to Federal power marketing administrations regarding repayment of the Federal investment. In addition, policies issued by the Commission provide guidance on separate accounting for transmission system costs. *See, e.g., Bonneville Power Admin.*, 25 FERC ¶ 61,140 (1983).

1.2.1.1 Legal Requirements Governing BPA's Revenue Requirement

BPA constructs, operates, and maintains the FCRTS within the Pacific Northwest and makes improvements or replacements to the transmission system 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. Transmission System Act § 4, 16 U.S.C. § 838b.

BPA's rates must be set to ensure that revenues are sufficient to recover costs. This requirement was first set forth in section 7 of the Bonneville Project Act, 16 U.S.C. § 832f , which provides that

> [r]ate 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. In 1974, section 9 of the Transmission System Act, 16 U.S.C. § 838g, expanded the cost recovery principle so that BPA's rates also would be set to recover

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

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

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

Section 7(a)(2) of the Northwest Power Act, 16 U.S.C. § 839e(a)(2), provides that the Commission shall issue a confirmation and approval of BPA's rates upon a finding that the 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.

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

1.2.1.2 The BPA Appropriations Refinancing Act

As in the last rate period, BPA's transmission rates for the FY 2016–17 rate period will reflect the requirements of the Refinancing Act, 16 U.S.C. § 838l, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, Pub. 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 U.S. Treasury yield curve prevailing at the time of the refinancing transaction. 16 U.S.C. § 838l(a)(6)(A).

The Refinancing Act restricted 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 dates on new principal amounts may not be earlier than the repayment dates for old capital investments. 16 U.S.C. § 838l(d). The Refinancing Act further directs the Administrator to offer to provide assurance in new or existing contracts for power, transmission, or related services that the Government will not increase the repayment obligations in the future. 16 U.S.C. § 838l(i).

1.2.2 Repayment Requirements and Policies

1.2.2.1 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, the Commission 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. *Bonneville Power Admin*., 20 FERC ¶ 61,142 (1982). The Commission required BPA to establish books of account for the FCRTS separate from its generation books of account; 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 those for its generation function. Such studies must set forth the date of each investment, the repayment date, and the amount repaid from transmission revenues. *Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984).

The Commission approved BPA's methodology for separate repayment studies in 1984. *Bonneville Power Admin*., 28 FERC ¶ 61,325 (1984). Thus, BPA has prepared separate repayment studies for its transmission and generation functions since 1984. This methodology has enabled BPA to set power and transmission rates separately with minimal change in repayment policy and the process for developing each revenue requirement. This study incorporates only the repayment study for the transmission function for FY 2016–2017.

1.2.2.2 Repayment Schedules

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

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 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 the Federal Energy Regulatory Commission) 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. 89-1409, 2d Sess., at 9-10 (1966). As stated in that report:

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

> power and permits Bonneville Power Administration customers, which include both electric utilities and electroprocess 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 were set forth in the Department of the Interior Manual, Part 730, Chapter 1:

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

To achieve a greater degree of uniformity in repayment policy for all Federal power marketing administrations, the Deputy Assistant Secretary of the Department of the Interior (DOI) issued a memo on August 2, 1972, outlining (1) a uniform definition of the start 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 ensuring that BPA still complies with the prescribed repayment period established for each increment of investment.

A further clarification of the repayment policy was outlined in a joint memo on 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 and obligations within the prescribed repayment periods, revenues shall be adequate, except in unusual circumstances, to repay annually all costs for O&M, purchased power, and interest.

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

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

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

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

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

(5) Repay:

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

(6) As required by Pub. L. No. 89-448, § 2, repay the portion of construction costs at Federal reclamation projects that is beyond the repayment ability of the irrigators, and which is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their payments on construction costs.

The typical repayment period for appropriated capital investments for generation is 50 years from the year in which the plant is placed in service. Appropriated transmission investments have due dates set at no more than 45 years. The Refinancing Act (*see* section 1.2.1.2) overrides provisions in DOE Order 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 investments.

Other sections within DOE Order 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 ensuring that BPA still completes repayment of each increment of Federal investment and obligation within its prescribed repayment period.

2. DEVELOPMENT OF REVENUE REQUIREMENT

2.1 Spending Level Development

The development of program spending levels occurs outside the rate process. For the FY 2016–2017 rate period it began in February and March of 2014, when BPA hosted the 2014 Capital Investment Review (CIR), a public process focused on reviewing and discussing draft asset strategies and 10-year capital forecasts. It continued with the 2014 Integrated Program Review (IPR), which provided customers and constituents an opportunity to examine, understand, and comment on BPA's cost projections for BPA's power and transmission functions.

BPA began the 2014 IPR discussion in May 2014 with the release of the IPR initial report and an opening workshop on May 28 containing an overview of Power Services', Transmission Services', and corporate agency services' proposed expense spending levels for FY 2015–2017 (the cost evaluation period). The initial report and workshop discussed proposed expense spending levels, particularly for the FY 2016–2017 rate period; the drivers, goals, and risks associated with the proposed expense spending levels; and comparisons to previous IPR costs. The initial report also included capital cost projections for FY 2016–2017, informed by the CIR process. After the opening IPR workshop and release of information, participants had ten days to request additional information or specific workshop topics.

BPA responded to requests for additional information and held three days of workshops in June 2014 to discuss the projected spending levels of many program areas, including the Columbia Generating Station (CGS), Corps, Reclamation, BPA's energy efficiency, transmission and fish and wildlife programs, and BPA's information technology program. While debt management actions are outside the scope of the IPR, workshops were held to enhance participants' understanding of the implications of past debt management decisions, proposed capital spending, and potential debt management tools. After considering the comments received, BPA released a final IPR close-out report in October 2014.

This study incorporates the spending levels identified in the 2014 IPR final close-out report, which can be found on BPA's public website: Finance & Rates—Financial Public Processes—Integrated Program Review.

2.2 Financial Risk and Mitigation

In its 1993 rate case BPA adopted a long-term policy that called for setting rates sufficient for the agency to achieve a 95 percent TPP; that is, a 95 percent probability of making both end-of-year U.S. Treasury payments in full and on time during each two-year rate period (1993 Administrator's Record of Decision, WP-93-A-02, at 72–73). Beginning with the 2002 power and transmission rates, this standard was applied separately to the transmission and generation functions. The 95 percent TPP standard was reaffirmed in BPA's Financial Plan published in 2008. BPA's Financial Plan (2008) and 10-Year Financial Plan (1993) can be found on BPA's public website at Finance & Rates—Financial Information—Financial Plan.

The purpose of the risk analysis is to ensure that the proposed rates will be sufficient to meet BPA's TPP standard. In this rate proceeding, BPA has analyzed its transmission risks and has determined that this rate proposal meets the 95 percent two-year TPP standard for the transmission function for the two-year rate period.

2.2.1 Financial Risk Mitigation Tools

To achieve this level of TPP, the following risk mitigation tools are employed:

Financial reserves. Financial reserves comprise cash and other investment instruments in the BPA Fund in the U.S. Treasury and deferred borrowing. Only financial reserves attributed to Transmission Services (TS) are considered in the transmission risk analysis; reserves attributed to Power Services are excluded. Some financial reserves are considered to be not available for risk; such encumbered reserves are not considered in the risk analysis. Encumbered reserves include customer deposits for capital projects related to Large or Small Generator Interconnection Agreements (LGIA or SGIA), Network Open Season, the Southern Intertie capital program, and Master Lease funds. These encumbered reserves are deposits from third parties to pay for specific facilities, security deposits from third parties, or advances through BPA's Master Lease program that are required by the lease agreement terms to be used only for specified projects. Encumbered reserves attributed to TS equaled $107.1 million at the start of FY 2015. Financial reserves available for risk attributed to TS (TS Reserves) were $510.9 million at the beginning of FY 2015.

Planned Net Revenue for Risk (PNRR). PNRR is a component of the revenue requirement that is added if TS Reserves are not sufficient to achieve a 95 percent TPP. When added to the revenue requirement, PNRR increases rates and therefore adds to cash flows, which augment TS Reserves. The appropriate amount of PNRR is the amount that is just sufficient to increase TPP until it meets the TPP standard. Since the TPP in this proposal is above 95 percent, no PNRR is required. Transmission Revenue Requirement Study Documentation, BP-16-E-BPA-08A, ch. 10.8.

Two-Year Rate Period. BPA is setting rates for a two-year rate period. The ability to revise rates after two years serves as an important risk mitigation tool for BPA's transmission function. By using a two-year rate period, BPA limits the amount of risk that must be covered by TS Reserves and PNRR before rates are set again.

2.2.2 Transmission Risk Analysis

To determine whether transmission rates satisfy BPA's 95 percent TPP standard, BPA performs a risk analysis using a technique known as Monte Carlo simulation. Monte Carlo simulation is a method of determining a set or distribution of possible outcomes resulting from the combination of various uncertain, that is, variable, inputs. The outcomes of primary interest in this risk analysis are the possible levels of TS Reserves at the end of each of the two years of the rate period. The level of TS Reserves at the end of a year is computed by adding the TS cash flow for that year to the level of TS Reserves at the end the previous year. The Monte Carlo simulation is performed by running multiple trial runs, called games or iterations. In the case of this risk analysis, many of the factors that will affect future TS cash flows have uncertain future values. We call these input variables—they can vary, that is, they do not have future values we know for certain, and they are inputs to the calculations of future TS cash flows and TS Reserves. An example of an input variable is interest expense in a specific year, which affects the levels of TS Reserves at the end of that year. Some of the interest expense will be for debt that has not yet been issued; the interest rate for that future debt is not known with certainty now. The range of future values these input variables can take is determined by observing the historical values and/or from subject matter expert opinion. In each game of the Monte Carlo simulation, a value for each input variable is randomly chosen from its defined range. Each of these values, along with deterministic input values (inputs that are assumed to have no uncertainty) are aggregated, generating a single annual TS cash flow value for that game.

Performing this 3,200 times generates a range of possible outcomes—that is, a probability distribution of annual cash flows and levels of TS Reserves. In ratesetting, this method is used to estimate the probability that TS Reserves at the start of the rate period plus the TS cash flow during the rate period will be sufficient to meet all cash obligations associated with TS during the rate period. Using the three-year timeframe permits modeling of the uncertainty in revenues and expenses between the time of preparation of the initial proposal studies now, in FY 2015, and the beginning of the rate period. This approach is required because the level of TS Reserves at the start of the FY 2016–2017 rate period, the primary tool for mitigating TS's FY 2016–2017 financial risk, cannot be known today; that level depends significantly on events yet to occur in FY 2015. Transmission Revenue Requirement Study Documentation, BP-16-E-BPA-08A, ch. 10.1.

The risk analysis simulates changes in TS Reserves from year to year throughout the FY 2015–2017 period for each of 3,200 games. The analysis estimates the probability that the Treasury payment for both years of the rate period will be made. Successful Treasury payment is deemed to occur in the model when the end-of-year TS Reserves, after Treasury payments are made, are sufficient to cover TS's liquidity need of $100 million. The liquidity need of $100 million is based on the historical monthly net cash flow patterns and monthly cash requirements for the transmission function. *Id.* ch. 10.6.

The risk analysis starts from a known level of TS Reserves at the beginning of FY 2015 and simulates the variability in revenue and expenses that affects the level of reserves throughout FY 2015 and also the possibility that some of the cash flow associated with the revenues and expenses will lag into the following fiscal year. When the model simulates the FY 2016–2017 rate period, it starts with the distribution of TS Reserves the model simulated for FY 2015.

The model then calculates the two-year TPP. If the TPP is below BPA's TPP standard, the model calculates the required amount of PNRR. Input values for point estimates of expenses (that is, deterministic estimates) come from this study (*see id.* ch. 3), and the revenue inputs come from the revenue forecast (Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 12). These inputs, when combined with inputs describing uncertainty in expenses and revenues (Transmission Revenue Requirement Study Documentation, BP-16-E-BPA-08A, ch. 10), provide the basis for the calculation of TPP and PNRR. The PNRR amount, if any, is an input to the transmission revenue requirement, increasing the transmission revenue requirement, transmission rates, and, finally, TS Reserves.

2.2.3 Transmission Risk Analysis Model

The risk analysis is performed using the Transmission Risk Analysis Model (TRAM). *Id.* ch. 10.1. TRAM is a Microsoft Excel® spreadsheet with the @RISK® add-in from Palisade Corporation (www.palisade.com). The @RISK® add-in adds features to Excel® that provide the ability to run Monte Carlo simulations within Excel®. TRAM can be run or interpreted only on computers with licensed copies of @RISK installed. TRAM runs 3,200 games for the three-year rate period and then counts the number of games in which the ending TS Reserves levels for both FY 2016 and FY 2017 are above the liquidity reserves level of $100 million. If this count is 3,040 (95 percent of 3,200) or higher, then the 95 percent TPP standard has been met. TRAM contains individual worksheets, including an income statement, a cash flow statement, and worksheets for some revenue and expense variables with uncertainty. *Id*. For more discussion of the risk analysis, see *id.* ch. 10.

2.2.4 Transmission Risk Analysis Results

The expected value (mean) from the resulting distribution for TS Reserves at the end of FY 2015 is $446 million; at the end of FY 2016, $417million; and at the end of FY 2017, $359 million. *Id.* ch. 10.7. The TPP is 99.9 percent, thus meeting BPA's TPP standard. *Id.*

2.3 Capital Investments

The forecast of BPA's capital investments for FY 2016–2017 used in setting the BP-16 transmission rates was produced in the CIR. The following section describes the capital investment forecasts.

BPA transmission capital outlay projections for the FY 2016–2017 rate period are $1,234 million. These investments are:

- transmission programs ($1,188.9 million)
- environmental program ($13.7 million)
- capital equipment ($32.3 million)

Id. ch. 7.

2.3.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be the primary source of capital used to finance projected FY 2016–2017 transmission capital program investments. Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to the interest rates for securities issued by other agencies of the U.S. Government. For interest rates on bonds projected to be issued, see *id.* ch. 6.

2.3.2 Federal Appropriations

This study includes the outstanding balances of the original capital investments in the Federal transmission system that was financed by Congressional appropriations. After the full implementation of BPA's self-funding authority under the Transmission System Act, transmission investments were no longer funded by annual appropriations. The Refinancing Act reset the unpaid principal of all outstanding BPA appropriations and assigned current market interest rates to the principal. 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, $1,461.9 million in BPA appropriations was outstanding. After implementation of the Refinancing Act, $1,075.4 million in BPA appropriations was outstanding. The Refinancing Act restricted prepayment of the new principal to $100 million in FY 1997–2001. Other repayment terms were unaffected. Through annual repayments, outstanding appropriations for transmission investments had been reduced to $200 million as of September 30, 2014.

2.3.3 Use of Financial Reserves for Capital Investment

As a means to fund capital investments in lieu of borrowing, BPA will draw $15 million per year from TS Reserves.

2.3.4 Non-Federal Payment Obligations

The transmission revenue requirements reflect two forms of non-Federal payment obligations. The first is lease financing arrangements for asset purchases. BPA entered into a transaction in 2004 with the Northwest Infrastructure Financing Corporation (NIFC), a subsidiary of JH Management, to provide for the construction of the 500-kV Schultz-Wautoma transmission line (Schultz-Wautoma line). NIFC will issue bonds to finance the construction. BPA will make semiannual lease payments to NIFC for 30 years, concluding with a single payment for the principal due on the bonds.

Payment of the debt incurred by NIFC to construct the line is secured solely by BPA's revenues. During the term of the lease, BPA will operate the Schultz-Wautoma line and provide transmission and ancillary services over the facilities. Since the completion of the Schultz-Wautoma project, BPA has entered into additional lease financing arrangements with NIFC and another entity, the Port of Morrow, and will continue to do so. The revenue requirement includes all transactions BPA expects to complete by the date of the Final Proposal. It does not include forecasts of additional transactions.

The second form of non-Federal payment obligations included in the revenue requirement is the functional reassignment to Transmission Services of debt service (interest and principal) payment obligations associated with non-Federal Energy Northwest (EN) bonds. This reassignment is a result of BPA's Debt Optimization Program (DOP), which refinances and repays existing EN bonds before they come due and uses the revenues made available from such refinancing to replenish or create opportunities to replenish BPA's Treasury borrowing authority by retiring additional Treasury obligations in amounts equal to the principal of the new EN bonds. When Treasury obligations associated with transmission investments are repaid under DOP, the debt service obligation associated with new EN debt in equivalent principal amounts is assigned to Transmission Services. The revenue requirements reflect refinancing actions that have occurred through FY 2009, when DOP ended. The revenue requirement does not include forecasts of additional refinancing activities during the rate period.

For specific calculations regarding non-Federal payment obligations, see *id.* ch. 8.

2.3.5 Customer-Financed Projects

The revenue requirements also reflect the impacts of customer-financed projects. Customers have financed two types of capital construction projects. The first form of customer financing occurs under generation interconnection agreements (LGIA or SGIA). BPA amended its Open Access Transmission Tariff and adopted the LGIA and SGIA in voluntary compliance with Commission Order Nos. 2003 and 2006. Under the generator interconnection agreements, interconnection customers finance the cost of Network Upgrades (facilities at or beyond the point at which the customer's interconnection facilities connect to BPA's transmission system) needed to interconnect their generating facilities to BPA's transmission system if BPA, as the transmission owner/provider, does not provide the funding. BPA requires the interconnection customer to advance funds in an amount sufficient to cover the cost of construction. These advance funds, with interest on the outstanding balance, are then returned to the interconnection customer in the form of transmission credits. These credits either offset charges for eligible transmission service in the customer's bill or are provided as monthly cash payments based on the generating facility's capacity and its plant capacity factor.

The second form of customer-financed projects is the customer-financed upgrade on the California-Oregon Intertie (COI). The COI upgrade increases COI and Pacific Direct-Current Intertie (PDCI) availability so that BPA will be able to support requests for long-term firm transmission service up to the full rating of the COI and PDCI. Like the advance funds provided under generator interconnection agreements, the advance funds provided by customers for the COI upgrade, with interest, will be returned to customers in the form of transmission credits that offset eligible charges for transmission service.

These customer-financed transactions and the associated transmission credits affect several areas of the revenue requirement. Depreciation of the associated assets appears in total transmission depreciation. The interest that accrues on the outstanding credit balances is included in non-Federal interest, a component of the net interest calculation on the income statement. Both of these items increase transmission expenses. These items also appear in the statement of cash flows, because they are non-cash expenses. In addition, the revenues associated with customer-financed projects for which customers receive credits affect the statement of cash flows because they are non-cash revenues—they provide no cash for cost recovery. Therefore, they generally increase the need for Minimum Required Net Revenue (MRNR), which is added to the income statement if necessary to ensure that all cash requirements are met.

Non-cash expenses (depreciation and interest on outstanding credit balances) offset non-cash revenues and decrease the need for MRNR. The non-cash expenses are subtracted from the non-cash revenues. If the difference is positive, meaning that non-cash revenues exceed non-cash expenses, the need for MRNR increases. If the difference is negative, meaning that non-cash expenses exceed non-cash revenues, the need for MRNR decreases.

For the forecasts of interest expense and transmission credits associated with generator interconnection agreements and with the COI upgrade at current and proposed rates, see Transmission Rates Study and Documentation, BP-16-E-BPA-07, tables 16.1 and 16.2.

2.4 Modeling of BPA's Repayment Obligations

Repayment studies are performed as part of the process for determining revenue requirements. The studies establish a schedule of annual U.S. Treasury amortization for the rate period and the resulting interest payments. Each repayment study covers a rate test year and the ensuing repayment period, which extends to the last year by which all outstanding and projected obligations must be repaid. For transmission repayment studies, that period is 35 years. This study horizon reflects the fact that bonds are not issued for terms longer than 35 years and that the outstanding appropriations and bonds that finance the transmission system are fully repaid within this period. This study horizon is also appropriate in that it does not exceed the estimated average service life of transmission system plant (45 years).

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

Appropriations and bonds are scheduled to be repaid within the expected useful life of the associated facility, or the maximum repayment period (50 years for generation and 35 years for transmission), whichever is less. Bonds issued by BPA to the U.S. Treasury have varying terms, taking into account the estimated average service lives for investments and prudent financing and cash management factors.

In the repayment studies, all projected bonds are issued with maturities not to exceed 30 years for transmission investment, although they can be refinanced within the 35-year repayment period. Environmental investments have a maximum term of 15 years. Corporate investments, generally for information technology, are for a 5-year period. Generally bonds are issued with a provision that allows the bonds to be called after a certain time, typically five years. Bonds also may be issued with no early call provision. Early retirement of eligible bonds may require that BPA pay a bond premium to the Treasury. Bonds may also be called and repaid at a discount. Bonds are issued to finance BPA transmission, environment, and corporate investments and are 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 interest expense by determining the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period.

For further discussion of the repayment program, see Transmission Revenue Requirement Study Documentation, BP-16-E-BPA-08A, ch. 15.

2.5 Products Used by Other Studies

This study produces the segmented revenue requirement, which allocates transmission costs among transmission segments. Chapter 2 of the documentation for this study describes the segmentation of the revenue requirement in detail. *Id.* ch. 2.2. The segmented revenue requirement is used in the Transmission Rates Study and Documentation to develop rates for the various transmission products. More detail on the transmission segments is available in the Transmission Segmentation Study and Documentation.

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3. TRANSMISSION REVENUE REQUIREMENTS

3.1 Revenue Requirement Format

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

The Income Statement (table 3) displays the components of the annual revenue requirements, which include total operating expenses (line 9), net interest expense (line 20), Minimum Required Net Revenue (line 22), and Planned Net Revenues for Risk (line 23). The sum of these four major components is the total revenue requirement (line 25) for each year of the rate period.

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

The Statement of Cash Flows (table 4) analyzes annual cash inflows and outflows. Cash provided by current operations (line 12), driven by expenses not requiring cash and non-cash revenues, shown in lines 5 through 11, must be sufficient to compensate for the difference between cash used for capital investments (line 16) and cash from treasury borrowing (line 23). If cash provided by current operations is not sufficient, Minimum Required Net Revenue (line 2) must be included in revenue requirements to accommodate the shortfall, yielding at least a zero annual increase in cash (line 24). The Minimum Required Net Revenue amount shown on the Statement of Cash Flows (line 2) then is incorporated in the Income Statement (table 3, line 22).

3.2 Current Revenue Test

Consistent with DOE Order RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test, exhibited in tables 5 and 6, determines whether the revenue expected from current rates will meet cost recovery requirements during the FY 2016–2017 rate period and the ensuing repayment period. For revenue at current rates, see Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 12.

The result of the current revenue test demonstrates that projected revenue from current rates is inadequate to meet the cost recovery criteria of Order RA 6120.2 over the repayment period, because the net position is negative. *See* table 7, column K. If revenues from current rates were adequate, current rates could be extended, although other reasons may exist for revising rates, such as the implementation of a new rate design.

3.3 Revised Revenue Test

Consistent with DOE Order RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenue projected from proposed rates will meet cost recovery requirements for the rate period. The revised revenue test is conducted using the forecast of revenue under proposed rates. Transmission Rates Study and Documentation, BP-16-E-BPA-07, table 12.

For the rate period, the demonstration of the adequacy of proposed rates is shown in tables 8 and 9. Table 9 tests the sufficiency of the resulting net revenues from table 8, line 23 for making the planned annual amortization payments. The sufficiency of net revenues is demonstrated by the annual increase (decrease) in cash (table 9, line 25). The annual cash flow must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash requirements.

The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill cost recovery requirements for the rate period, FY 2016–2017. With the successful test of proposed rates, the rate development process ends.

3.4 Repayment Test at Proposed Rates

Table 10, Transmission Revenues from Proposed Rates, demonstrates whether projected revenue from proposed rates is adequate to meet the cost recovery criteria of DOE Order RA 6120.2 over the repayment period. The data are presented in a format consistent with the revised revenue tests, tables 8 and 9, and the separate accounting analysis that is an attachment to the rate filing BPA submits to the Commission. The focal point of table 10 is the net position (column K), which is the amount of funds provided by revenues that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the net position is zero or greater in each of the years of the rate 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 zero or greater for each year of the rate 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 period data have been developed specifically for this study. The repayment period data are presented consistent with the requirements of DOE Order RA 6120.2.

Table 11, Amortization of Transmission Investments Over Repayment Period, summarizes the amortization of Federal investments over the repayment period. It displays the total investment costs through the cost evaluation period, forecast replacements required to maintain the system through the repayment period, the cumulative dollar amount of investments placed in service, scheduled amortization payments for each year of the repayment period (due and discretionary), unamortized investments including replacements through the repayment period, unamortized obligations as determined by a term schedule (if all obligations were paid at maturity and never early), and the predetermined amortization payments and the unamortized amount of irrigation assistance for each year of the repayment period.

TABLES

Table 1: Projected Net Revenues From Proposed Rates
($000s)

		A	B	C
		FY 2016	FY 2017	RATE PERIOD AVERAGE
1	PROJECTED REVENUES FROM PROPOSED RATES	1,098,132	1,108,416	$1,103,274
2	PROJECTED EXPENSES	987,216	1,022,811	1,005,014
3	NET REVENUES	$110,916	$85,605	$98,260

Table 2: Planned Repayments to U.S. Treasury
($000s)

		A	B	C
		BOND AMORTIZATION	APPROPRIATIONS AMORTIZATION	TOTAL
1	2016	$19,500	$40,950	$60,450
2	2017	83,670	54,110	137,780
3	TOTAL	$103,170	$95,060	$198,230

Table 3: Transmission Revenue Requirement Income Statement
($000s)

		A	B
		FY 2016	FY 2017
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	155,274	160,800
3	TRANSMISSION ENGINEERING	54,421	54,915
4	TRANSMISSION MAINTENANCE	162,552	164,272
5	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	140,767	140,782
6	BPA INTERNAL SUPPORT	85,106	86,915
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	(2,100)	(2,100)
8	DEPRECIATION & AMORTIZATION	239,852	259,210
9	TOTAL OPERATING EXPENSES	835,872	864,796
10	INTEREST EXPENSE		
11	INTEREST EXPENSE		
12	FEDERAL APPROPRIATIONS	14,418	8,351
13	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
14	ON LONG-TERM DEBT	121,950	147,551
15	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
16	DEBT SERVICE REASSIGNMENT INTEREST	31,431	23,072
17	NON-FEDERAL INTEREST	52,170	53,032
18	PREMIUMS/DISCOUNTS	-	-
18	AFUDC	(40,657)	(40,446)
19	INTEREST INCOME	(9,560)	(15,137)
20	NET INTEREST EXPENSE	151,344	158,016
21	TOTAL EXPENSES	987,216	1,022,811
22	MINIMUM REQUIRED NET REVENUE 1/	109,840	86,677
23	PLANNED NET REVENUES FOR RISK	-	-
24	TOTAL PLANNED NET REVENUE	109,840	86,677
25	TOTAL REVENUE REQUIREMENT	1,097,057	1,109,488
	1/ See note on cash flow table		

Table 4: Transmission Revenue Requirement Statement of Cash Flows
($000s)

		A	B
		FY 2016	FY 2017
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUE	109,840	86,677
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	239,852	259,210
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	4,326	4,252
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(38,893)	(28,343)
11	AC INTERTIE CO/FIBER	(6,853)	(6,853)
12	CASH PROVIDED BY CURRENT OPERATIONS	304,865	311,536
13	CASH USED FOR CAPITAL INVESTMENTS:		
14	INVESTMENT IN:		
15	UTILITY PLANT	(658,667)	(576,229)
16	CASH USED FOR CAPITAL INVESTMENTS	(658,667)	(576,229)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
18	INCREASE IN LONG-TERM DEBT	643,667	561,229
19	DEBT SERVICE REASSIGNMENT PRINCIPAL	(185,303)	(199,991)
20	REPAYMENT OF CAPITAL LEASES	(1,392)	(1,486)
21	REPAYMENT OF LONG-TERM DEBT	(19,500)	(40,950)
22	REPAYMENT OF CAPITAL APPROPRIATIONS	(83,670)	(54,110)
23	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	353,802	264,692
24	ANNUAL INCREASE (DECREASE) IN CASH [1/]	-	-
25	PLANNED NET REVENUE FOR RISK	-	-
26	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	-	-

1/ Line 24 must be greater than or equal to zero, otherwise planned net revenues for risk will be added so that there are no negative cash flows for the year.

Table 5: Current Revenue Test Income Statement
($000s)

		A	B
		FY 2016	FY 2017
1	REVENUES FROM CURRENT RATES	1,039,115	1,048,878
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	155,274	160,800
4	TRANSMISSION ENGINEERING	54,421	54,915
5	TRANSMISSION MAINTENANCE	162,552	164,272
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	140,767	140,782
7	BPA INTERNAL SUPPORT	85,106	86,915
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(2,100)	(2,100)
9	DEPRECIATION & AMORTIZATION	239,852	259,210
10	TOTAL OPERATING EXPENSES	835,872	864,796
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	14,418	8,351
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	121,950	147,551
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
17	DEBT SERVICE REASSIGNMENT INTEREST	31,431	23,072
18	NON-FEDERAL INTEREST	52,170	53,032
17	PREMIUMS/DISCOUNTS	-	-
19	AFUDC	(40,657)	(40,446)
20	INTEREST INCOME	(9,560)	(15,137)
21	NET INTEREST EXPENSE	151,344	158,016
22	TOTAL EXPENSES	987,216	1,022,811
23	NET REVENUES	51,899	26,067

Table 6: Current Revenue Test Statement of Cash Flows
($000s)

		A	B
		FY 2016	FY 2017
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	51,899	26,067
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	239,852	259,210
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	4,326	4,252
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(38,893)	(28,343)
11	AC INTERTIE CO/FIBER	(6,853)	(6,853)
12	CASH PROVIDED BY CURRENT OPERATIONS	246,924	250,926
13	CASH USED FOR CAPITAL INVESTMENTS:		
14	INVESTMENT IN:		
15	UTILITY PLANT	(658,667)	(576,229)
16	CASH USED FOR CAPITAL INVESTMENTS	(658,667)	(576,229)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
18	INCREASE IN LONG-TERM DEBT	643,667	561,229
19	DEBT SERVICE REASSIGNMENT PRINCIPAL	(185,303)	(199,991)
20	REPAYMENT OF CAPITAL LEASES	(1,392)	(1,486)
21	REPAYMENT OF LONG-TERM DEBT	(19,500)	(40,950)
22	REPAYMENT OF CAPITAL APPROPRIATIONS	(83,670)	(54,110)
23	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	353,802	264,692
24	ANNUAL INCREASE (DECREASE) IN CASH	(57,941)	(60,610)

1/ Line 24 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 7: Transmission Revenues from Current Rates – Results Through the Repayment Period

($000s)

		A	B	C	D	E	F	G	H	I	J	K
	YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	DEBT SERVICE OFFSETS (REV REQ STUDY DOC)	DEPRECIATION	NET INTEREST (TABLE D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	NET POSITION (K=H-I-J)
	COMBINED CUMULATIVE											
1	**1977**	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
2	**1978-2012**	18,593,390	8,366,918		4,268,933	5,053,564	903,975	3,867,160	6,088,950	5,548,364	56,940	483,646
	TRANSMISSION											
3	**2013**	979,873	567,843		206,545	136,623	68,862	196,098	264,960	56,374	166,810	41,776
4	**2014**	1,052,296	577,717		213,257	108,126	153,196	202,107	355,303	104,486	176,317	74,500
	COST EVALUATION											
5	**PERIOD**											
6	**2015**	1,033,457	589,077		223,380	118,237	102,763	182,520	285,283	98,119	186,471	693
	RATE APPROVAL											
7	**PERIOD**											
8	**2016**	1,039,115	596,020		239,852	151,344	51,899	180,025	231,924	103,170	186,696	(57,941)
9	**2017**	1,048,878	605,585		259,210	158,016	26,067	209,859	235,926	95,060	201,476	(60,610)
	REPAYMENT											
	PERIOD											
10	**2018**	1,048,878	605,585	(7,754)	259,210	167,395	24,441	209,859	234,300	101,821	193,089	(60,610)
11	**2019**	1,048,878	605,585	(8,048)	259,210	165,625	26,505	209,859	236,365	290,644	6,330	(60,610)
12	**2020**	1,048,878	605,585	(8,342)	259,210	168,211	24,214	209,859	234,073	273,534	21,149	(60,610)
13	**2021**	1,048,878	605,585	(8,544)	259,210	183,522	9,105	209,859	218,964	257,344	22,230	(60,610)
14	**2022**	1,048,878	605,585	(8,829)	259,210	181,476	11,436	209,859	221,295	259,316	22,589	(60,610)
15	**2023**	1,048,878	605,585	(9,082)	259,210	175,994	17,171	209,859	227,030	264,468	23,172	(60,610)
16	**2024**	1,048,878	605,585	(9,366)	259,210	167,865	25,583	209,859	235,443	277,888	18,164	(60,610)
17	**2025**	1,048,878	605,585	(9,577)	259,210	178,936	14,724	209,859	224,583	284,636	557	(60,610)
18	**2026**	1,048,878	605,585	(9,767)	259,210	180,954	12,896	209,859	222,755	282,769	596	(60,610)
19	**2027**	1,048,878	605,585	(9,958)	259,210	186,872	7,169	209,859	217,028	277,000	638	(60,610)
20	**2028**	1,048,878	605,585	(10,163)	259,210	193,349	897	209,859	210,757	270,684	683	(60,610)
21	**2029**	1,048,878	605,585	(10,322)	259,210	192,774	1,631	209,859	211,490	271,389	711	(60,610)
22	**2030**	1,048,878	605,585	(10,488)	259,210	190,716	3,854	209,859	213,714	273,568	756	(60,610)
23	**2031**	1,048,878	605,585	(10,652)	259,210	194,973	(238)	209,859	209,621	269,422	809	(60,610)
24	**2032**	1,048,878	605,585	(10,858)	259,210	195,970	(1,029)	209,859	208,830	268,574	866	(60,610)
25	**2033**	1,048,878	605,585	(11,045)	259,210	201,487	(6,359)	209,859	203,501	173,495	90,615	(60,610)
26	**2034**	1,048,878	605,585	(11,223)	259,210	197,856	(2,550)	209,859	207,309	237,031	30,888	(60,610)
27	**2035**	1,048,878	605,585	(11,419)	259,210	209,986	(14,484)	209,859	195,375	254,923	1,061	(60,610)
28	**2036**	1,048,878	605,585	(11,624)	259,210	211,809	(16,103)	209,859	193,757	253,231	1,136	(60,610)
29	**2037**	1,048,878	605,585	(11,814)	259,210	220,227	(24,330)	209,859	185,530	94,924	151,216	(60,610)
30	**2038**	1,048,878	605,585	(11,984)	259,210	224,521	(28,454)	209,859	181,405	57,344	184,671	(60,610)
31	**2039**	1,048,878	605,585	(12,171)	259,210	226,088	(29,834)	209,859	180,026	86,563	154,073	(60,610)
32	**2040**	1,048,878	605,585	(12,346)	259,210	227,807	(31,378)	209,859	178,482	104,411	134,681	(60,610)
33	**2041**	1,048,878	605,585	(12,506)	259,210	232,519	(35,930)	209,859	173,929	57,327	177,212	(60,610)
34	**2042**	1,048,878	605,585	(12,673)	259,210	234,348	(37,592)	209,859	172,267	91,062	141,815	(60,610)
35	**2043**	1,048,878	605,585	(12,863)	259,210	241,371	(44,425)	209,859	165,434	31,065	194,979	(60,610)
36	**2044**	1,048,878	605,585	(13,045)	259,210	239,669	(42,541)	209,859	167,318	155,379	72,549	(60,610)
37	**2045**	1,048,878	605,585	(13,271)	259,210	241,510	(44,156)	209,859	165,703	226,313	-	(60,610)
38	**2046**	1,048,878	605,585	(13,443)	259,210	247,479	(49,953)	209,859	159,907	220,516	-	(60,610)
39	**2047**	1,048,878	605,585	(13,576)	259,210	253,974	(56,315)	209,859	153,544	214,154	-	(60,610)
40	**2048**	1,048,878	605,585	(13,747)	259,210	261,020	(63,191)	209,859	146,669	207,279	-	(60,610)
41	**2049**	1,048,878	605,585	(13,953)	259,210	268,695	(70,660)	209,859	139,199	199,809	-	(60,610)
42	**2050**	1,048,878	605,585	(14,139)	259,210	277,045	(78,824)	209,859	131,036	191,646	-	(60,610)
43	**2051**	1,048,878	605,585	(14,257)	259,210	286,049	(87,709)	209,859	122,150	182,760	-	(60,610)
44	**2052**	1,048,878	605,585	(14,376)	259,210	295,698	(97,239)	209,859	112,620	173,230	-	(60,610)
	TRANSMISSION											
45	**TOTALS**	60,457,746	33,104,232	(397,227)	14,483,534	13,249,698	623,094	12,182,848	14,123,756	13,141,095	1,283,224	(1,639,283)

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

Table 8: Revised Revenue Test Income Statement
($000s)

		A	B
		FY 2016	FY 2017
1	REVENUES FROM PROPOSED RATES	1,098,132	1,108,416
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	155,274	160,800
4	TRANSMISSION ENGINEERING	54,421	54,915
5	TRANSMISSION MAINTENANCE	162,552	164,272
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	140,767	140,782
7	BPA INTERNAL SUPPORT	85,106	86,915
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(2,100)	(2,100)
9	DEPRECIATION & AMORTIZATION	239,852	259,210
10	TOTAL OPERATING EXPENSES	835,872	864,796
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	14,418	8,351
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	121,950	147,551
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
17	DEBT SERVICE REASSIGNMENT INTEREST	31,431	23,072
18	NON-FEDERAL INTEREST	52,170	53,032
19	PREMIUMS/DISCOUNTS	-	-
19	AFUDC	(40,657)	(40,446)
20	INTEREST INCOME	(9,560)	(15,137)
21	NET INTEREST EXPENSE	151,344	158,016
22	TOTAL EXPENSES	987,216	1,022,811
23	NET REVENUES	110,916	85,605

Table 9: Revised Revenue Test Statement of Cash Flows
($000s)

				A	B
				FY 2016	FY 2017
1	CASH FROM CURRENT OPERATIONS:				
2		NET REVENUES		110,916	85,605
3		DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING		15,000	15,000
4		EXPENSES NOT REQUIRING CASH:			
5			DEPRECIATION & AMORTIZATION	239,852	259,210
6			TRANSMISSION CREDIT PROJECTS NET INTEREST	4,326	4,252
7			AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
8			CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9		NON-CASH REVENUES/ACCRUAL REVENUES			
10			LGIA	(38,893)	(28,343)
11			AC INTERTIE CO/FIBER	(6,853)	(6,853)
12		CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION		(1,074)	1,074
13	CASH PROVIDED BY CURRENT OPERATIONS			304,867	311,538
14	CASH USED FOR CAPITAL INVESTMENTS:				
15		INVESTMENT IN:			
16			UTILITY PLANT	(658,667)	(576,229)
17	CASH USED FOR CAPITAL INVESTMENTS			(658,667)	(576,229)
18	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:				
19		INCREASE IN LONG-TERM DEBT		643,667	561,229
20		DEBT SERVICE REASSIGNMENT PRINCIPAL		(185,303)	(199,991)
21		REPAYMENT OF CAPITAL LEASES		(1,392)	(1,486)
22		REPAYMENT OF LONG-TERM DEBT		(19,500)	(40,950)
23		REPAYMENT OF CAPITAL APPROPRIATIONS		(83,670)	(54,110)
24	CASH FROM TREASURY BORROWING AND APPROPRIATIONS			353,802	264,692
25	ANNUAL INCREASE (DECREASE) IN CASH			1	2
1/ Line 25 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 10: Transmission Revenues from Proposed Rates – Results Through the Repayment Period

($000s)

		A	B	C	D	E	F	G	H	I	J	K
	YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	DEBT SERVICE OFFSETS (REV REQ STUDY DOC)	DEPRECIATION	NET INTEREST (TABLE D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	NET POSITION (K=H-I-J)
	COMBINED CUMULATIVE											
1	**1977**	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
2	**1978-2012**	18,593,390	8,366,918		4,268,933	5,053,564	903,975	3,867,160	6,088,950	5,548,364	56,940	483,646
	TRANSMISSION											
3	**2013**	979,873	567,843		206,545	136,623	68,862	196,098	264,960	56,374	166,810	41,776
4	**2014**	1,052,296	577,717		213,257	108,126	153,196	202,107	355,303	104,486	176,317	74,500
	COST EVALUATION											
5	**PERIOD**											
6	**2015**	1,033,457	589,077		223,380	118,237	102,763	182,520	285,283	98,119	186,471	693
	RATE APPROVAL											
7	**PERIOD**											
8	**2016**	1,098,132	596,020		239,852	151,344	110,916	178,951	289,867	103,170	186,696	1
9	**2017**	1,108,416	605,585		259,210	158,016	85,605	210,933	296,538	95,060	201,476	2
	REPAYMENT PERIOD											
10	**2018**	1,108,416	605,585	(7,754)	259,210	167,395	83,979	210,933	294,912	101,821	193,089	2
11	**2019**	1,108,416	605,585	(8,048)	259,210	165,625	86,043	210,933	296,977	290,644	6,330	2
12	**2020**	1,108,416	605,585	(8,342)	259,210	168,211	83,752	210,933	294,685	273,534	21,149	2
13	**2021**	1,108,416	605,585	(8,544)	259,210	183,522	68,643	210,933	279,576	257,344	22,230	2
14	**2022**	1,108,416	605,585	(8,829)	259,210	181,476	70,973	210,933	281,907	259,316	22,589	2
15	**2023**	1,108,416	605,585	(9,082)	259,210	175,994	76,708	210,933	287,642	264,468	23,172	2
16	**2024**	1,108,416	605,585	(9,366)	259,210	167,865	85,121	210,933	296,055	277,888	18,164	2
17	**2025**	1,108,416	605,585	(9,577)	259,210	178,936	74,262	210,933	285,195	284,636	557	2
18	**2026**	1,108,416	605,585	(9,767)	259,210	180,954	72,434	210,933	283,367	282,769	596	2
19	**2027**	1,108,416	605,585	(9,958)	259,210	186,872	66,707	210,933	277,640	277,000	638	2
20	**2028**	1,108,416	605,585	(10,163)	259,210	193,349	60,435	210,933	271,369	270,684	683	2
21	**2029**	1,108,416	605,585	(10,322)	259,210	192,774	61,169	210,933	272,102	271,389	711	2
22	**2030**	1,108,416	605,585	(10,488)	259,210	190,716	63,392	210,933	274,326	273,568	756	2
23	**2031**	1,108,416	605,585	(10,652)	259,210	194,973	59,299	210,933	270,233	269,422	809	2
24	**2032**	1,108,416	605,585	(10,858)	259,210	195,970	58,508	210,933	269,442	268,574	866	2
25	**2033**	1,108,416	605,585	(11,045)	259,210	201,487	53,179	210,933	264,113	173,495	90,615	2
26	**2034**	1,108,416	605,585	(11,223)	259,210	197,856	56,988	210,933	267,921	237,031	30,888	2
27	**2035**	1,108,416	605,585	(11,419)	259,210	209,986	45,053	210,933	255,987	254,923	1,061	2
28	**2036**	1,108,416	605,585	(11,624)	259,210	211,809	43,435	210,933	254,369	253,231	1,136	2
29	**2037**	1,108,416	605,585	(11,814)	259,210	220,227	35,208	210,933	246,142	94,924	151,216	2
30	**2038**	1,108,416	605,585	(11,984)	259,210	224,521	31,084	210,933	242,017	57,344	184,671	2
31	**2039**	1,108,416	605,585	(12,171)	259,210	226,088	29,704	210,933	240,638	86,563	154,073	2
32	**2040**	1,108,416	605,585	(12,346)	259,210	227,807	28,160	210,933	239,094	104,411	134,681	2
33	**2041**	1,108,416	605,585	(12,506)	259,210	232,519	23,607	210,933	234,541	57,327	177,212	2
34	**2042**	1,108,416	605,585	(12,673)	259,210	234,348	21,946	210,933	232,879	91,062	141,815	2
35	**2043**	1,108,416	605,585	(12,863)	259,210	241,371	15,113	210,933	226,046	31,065	194,979	2
36	**2044**	1,108,416	605,585	(13,045)	259,210	239,669	16,997	210,933	227,930	155,379	72,549	2
37	**2045**	1,108,416	605,585	(13,271)	259,210	241,510	15,382	210,933	226,315	226,313	-	2
38	**2046**	1,108,416	605,585	(13,443)	259,210	247,479	9,585	210,933	220,518	220,516	-	2
39	**2047**	1,108,416	605,585	(13,576)	259,210	253,974	3,223	210,933	214,156	214,154	-	2
40	**2048**	1,108,416	605,585	(13,747)	259,210	261,020	(3,653)	210,933	207,281	207,279	-	2
41	**2049**	1,108,416	605,585	(13,953)	259,210	268,695	(11,122)	210,933	199,811	199,809	-	2
42	**2050**	1,108,416	605,585	(14,139)	259,210	277,045	(19,286)	210,933	191,648	191,646	-	2
43	**2051**	1,108,416	605,585	(14,257)	259,210	286,049	(28,171)	210,933	182,762	182,760	-	2
44	**2052**	1,108,416	605,585	(14,376)	259,210	295,698	(37,701)	210,933	173,232	173,230	-	2
	TRANSMISSION TOTALS											
45		62,660,124	33,104,232	(397,227)	14,483,534	13,249,698	2,825,472	12,220,440	16,363,727	13,141,095	1,283,224	600,688

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

Table 11: Amortization of Transmission Investments Over Repayment Period ($000s)

	A	B	C	D	E	F	G	H
		INVESTMENTS PLACED IN SERVICE						
	FISCAL YEAR	ORIGINAL & NEW OBLIGATIONS	REPLACEMENTS	CUMULATIVE AMOUNT IN SERVICE	DUE AMORTIZATION	DISCRETIONARY AMORTIZATION	UNAMORTIZED INVESTMENT	TERM INVESTMENT SCHEDULE
1	2013	11,184,408	-	11,184,408	-	-	2,734,752	7,075,176
2	2014	145,987	-	11,330,395	87,050	-	2,793,689	6,768,700
3	2015	609,250	-	11,939,645	166,300	1,319	3,235,320	6,988,763
4	2016	598,200	-	12,537,845	19,500	83,670	3,730,350	7,332,816
5	2017	545,300	-	13,083,145	40,950	54,110	4,180,590	7,449,817
6	2018	-	195,278	13,278,423	-	101,821	4,274,047	7,404,092
7	2019	-	202,689	13,481,112	159,750	130,894	4,186,091	7,279,578
8	2020	-	210,104	13,691,215	166,047	107,488	4,122,661	7,240,794
9	2021	-	215,186	13,906,402	97,250	160,094	4,080,503	7,295,493
10	2022	-	222,367	14,128,768	123,200	136,116	4,043,554	7,341,649
11	2023	-	228,727	14,357,495	60,300	204,168	4,007,813	7,510,076
12	2024	-	235,874	14,593,370	45,000	232,888	3,965,799	7,700,950
13	2025	-	241,196	14,834,566	192,000	92,636	3,922,359	7,635,213
14	2026	-	245,991	15,080,556	138,000	144,769	3,885,580	7,743,204
15	2027	-	250,787	15,331,343	277,000	-	3,859,367	7,632,991
16	2028	-	255,968	15,587,311	223,800	46,884	3,844,651	7,610,159
17	2029	-	259,963	15,847,274	243,000	28,389	3,833,226	7,611,400
18	2030	-	264,141	16,111,415	239,000	34,568	3,823,798	7,502,262
19	2031	-	268,275	16,379,690	181,698	87,724	3,822,651	7,121,538
20	2032	-	273,453	16,653,143	9,000	259,574	3,827,530	6,509,190
21	2033	-	278,179	16,931,322	21,000	152,495	3,932,214	5,957,407
22	2034	-	282,664	17,213,986	-	237,031	3,977,846	5,748,672
23	2035	-	287,600	17,501,586	-	254,923	4,010,523	5,640,382
24	2036	-	292,745	17,794,331	-	253,231	4,050,037	5,679,127
25	2037	-	297,546	18,091,877	-	94,924	4,252,660	5,787,673
26	2038	-	301,827	18,393,704	-	57,344	4,497,142	6,034,499
27	2039	-	306,532	18,700,235	-	86,563	4,717,111	6,177,031
28	2040	-	310,943	19,011,179	-	104,411	4,923,643	6,307,974
29	2041	-	314,969	19,326,148	-	57,327	5,181,285	6,576,003
30	2042	-	319,181	19,645,329	-	91,062	5,409,404	6,895,185
31	2043	-	323,949	19,969,278	-	31,065	5,702,288	7,002,133
32	2044	-	328,544	20,297,822	-	155,379	5,875,453	7,295,677
33	2045	-	334,222	20,632,044	-	226,313	5,983,362	7,599,899
34	2046	-	338,574	20,970,617	-	220,516	6,101,419	7,887,473
35	2047	-	341,921	21,312,538	-	214,154	6,229,186	8,229,394
36	2048	-	346,218	21,658,756	-	207,279	6,368,125	8,575,612
37	2049	-	351,395	22,010,152	-	199,809	6,519,711	8,927,007
38	2050	-	356,081	22,366,233	-	191,646	6,684,147	9,283,088
39	2051	-	359,069	22,725,302	-	182,760	6,860,456	9,642,158
40	2052	-	362,056	23,087,358	-	173,230	7,049,282	10,004,214
41	**TOTAL**	**$13,083,145**	**$10,004,214**		**$2,489,845**	**$5,098,576**		

BONNEVILLE POWER ADMINISTRATION
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