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-24 Rate Proceeding

Final Proposal

Transmission Revenue Requirement Study

BP-24-FS-BPA-06

July 2023

TRANSMISSION REVENUE REQUIREMENT STUDY

Table of Contents

Page

COMMONLY USED ACRONYMS AND SHORT FORMS iii

1. INTRODUCTION 1
- 1.1 Purpose of the Study 1
- 1.2 Legal Requirements 5
  - 1.2.1 Governing Authorities 5
    - 1.2.1.1 Legal Requirements Governing BPA's Revenue Requirement 6
    - 1.2.1.2 The BPA Appropriations Refinancing Act 8
  - 1.2.2 Repayment Requirements and Policies 8
    - 1.2.2.1 Separate Repayment Studies 8
    - 1.2.2.2 Repayment Schedules 9

2. DEVELOPMENT OF REVENUE REQUIREMENT 15
- 2.1 Forecast Cost Development 15
- 2.2 Capital Investments 16
  - 2.2.1 Bonds Issued to the Treasury 16
  - 2.2.2 Federal Appropriations 17
  - 2.2.3 Revenues for Capital Investment 17
  - 2.2.4 Non-Federal Payment Obligations 17
  - 2.2.5 Customer-Financed Projects 18
- 2.3 Modeling of BPA's Repayment Obligations 20
- 2.4 Change to Plant and Debt Assumptions 22

3. TRANSMISSION REVENUE REQUIREMENTS 23
- 3.1 Revenue Requirement Format 23
- 3.2 Current Revenue Test 24
- 3.3 Revised Revenue Test 24
- 3.4 Repayment Test at Proposed Rates 25

FIGURE AND TABLES

Figure 1: Transmission Revenue Requirement Process 3

Table 1: Projected Net Revenues from Proposed Rates 29
Table 2: Planned Repayments to U.S. Treasury 29
Table 3: Transmission Revenue Requirement Income Statement 30
Table 4: Transmission Revenue Requirement Statement of Cash Flows 31
Table 5: Transmission Current Revenue Test Income Statement 32
Table 6: Transmission Current Revenue Test Statement of Cash Flows 33
Table 7: Transmission Revenues from Current Rates – Results through the Repayment Period 34
Table 8: Transmission Revised Revenue Test Income Statement 35
Table 9: Transmission Revised Revenue Test Statement of Cash Flows 37
Table 10: Transmission Revenues from Proposed Rates through the Repayment Period 38
Table 11: Amortization of Transmission Investments Over Repayment Period 40

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission (see also “FERC”)
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also “NPCC”)
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service

DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	environmental impact statement
EN	Energy Northwest, Inc.
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
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	generation imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review

IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement

NUG	non-utility generation
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	oversupply
OY	operating year (August through July)
P10	tenth percentile of a given dataset
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
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
POR	point of receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRHL	Regional Residual Hydro Load
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability

RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
TGT	Townsend-Garrison Transmission
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	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool

This page intentionally left blank.

1. INTRODUCTION

1.1 Purpose of the Study

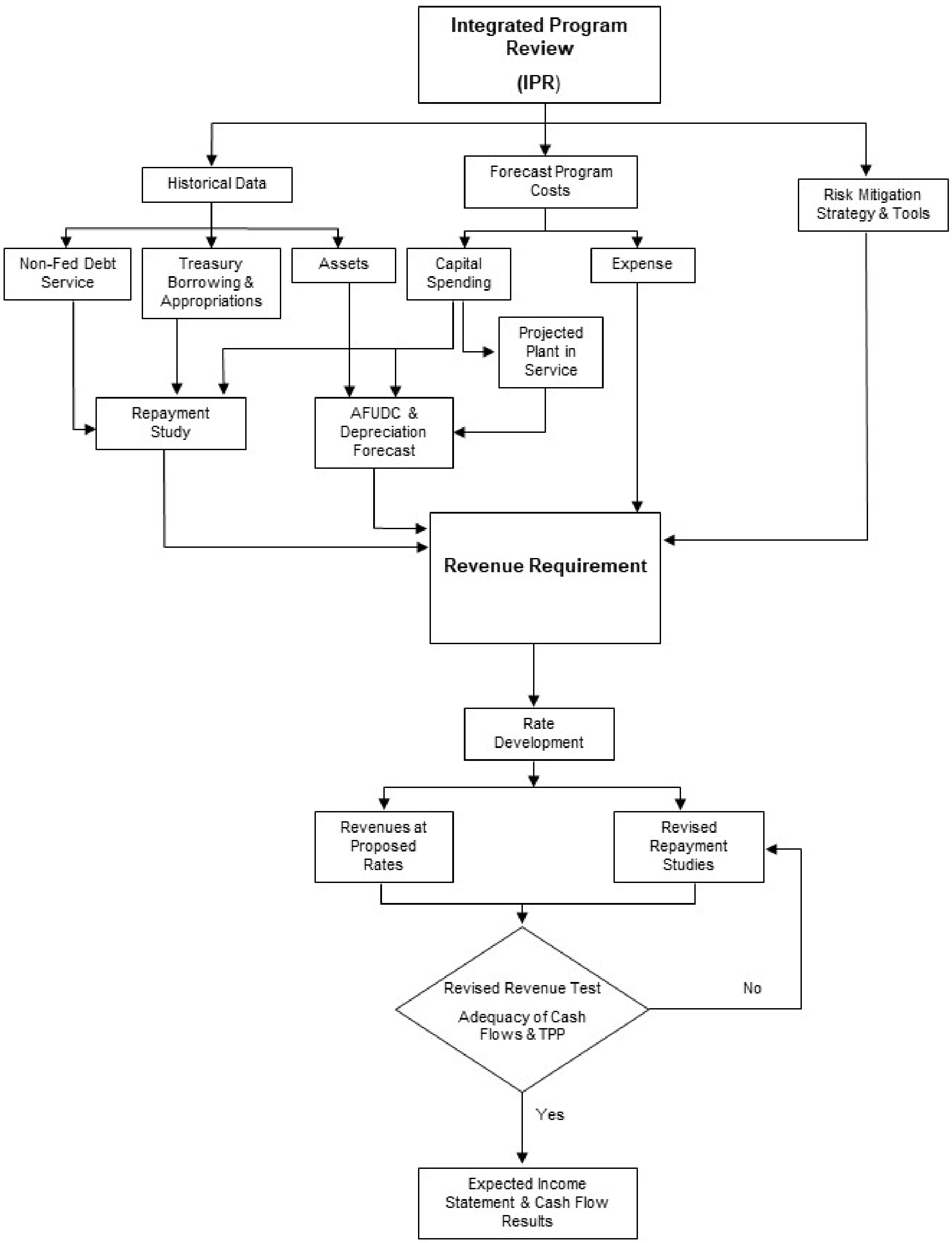
The purpose of the Transmission Revenue Requirement Study is to establish the revenues from transmission and ancillary services that are necessary to recover, in accordance with sound business principles, the Federal Columbia River Transmission System (FCRTS) costs associated with the transmission of 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 the Bonneville Power Administration's (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 (FERC or 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 filing includes Fiscal Year (FY) 2023 and the proposed rate period, FY 2024-2025. 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 BPA's power function. *See* Power Revenue Requirement Study, BP-24-FS-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-24-FS-BPA-06A, 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 composed 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, and other risk mitigation measures, as described in the Power and Transmission Risk Study, BP-24-FS-BPA-05. From these three steps, the revenue requirement is set at the level necessary to fulfill cost recovery requirements. This process is depicted in Figure 1, below.

Figure 1: Transmission Revenue Requirement Process



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 would not be adequate to 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. 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 the Power and Transmission Risk Study, BP-24-FS-BPA-05, § 5.2.4.2.

Table 1 (see Tables at the back of this document) summarizes the revised revenue test and shows projected net revenues from proposed transmission rates for FY 2024-2025. These net revenues are the lowest level sufficient to achieve, in combination with other risk mitigation tools, cost recovery 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, 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.

DOE Order "Power Marketing Administration Financial Reporting," RA 6120.2, issued by the Secretary of Energy, also 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:

> 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. 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:

> [P]ayments 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:

> 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

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, was 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). All of the appropriations refinanced by this Act have been repaid.

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 will 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 will be composed 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 2024-2025.

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 BPA customers 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 will 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 must 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 DOE on October 1, 1977. Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.* 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. Due dates for appropriated transmission investments were set at no more than 45 years. The Refinancing Act (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.

DOE Order RA 6120.2 also requires 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 Forecast Cost Development

The development of program spending levels occurs outside the rate process. For the FY 2024-2025 rate period it began in June 2022, when BPA hosted the first 2022 Integrated Program Review (IPR) workshop. This public process focused on reviewing and discussing expense projections and capital forecasts. The process 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 2022 IPR discussion with the release of the IPR initial publication and an opening workshop containing an overview of Power Services', Transmission Services', and corporate agency services' forecast expense and capital costs for FY 2024-2025. The opening workshop launched a public comment period, providing participants the opportunity to provide feedback on the forecast costs and program objectives. The initial publication and workshop discussed forecast costs and program objectives for the FY 2024-2025 rate period, with comparisons to previous IPR costs. The initial report also included capital cost projections for FY 2024-2025.

Following the opening workshop, BPA held a series of workshops to discuss spending levels for the 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. After considering the comments received, BPA released a final IPR closeout report in October 2022.

This study incorporates the spending levels identified in the 2022 IPR closeout report, which can be found on BPA's public website: https://www.bpa.gov/about/finance/bp-24-ipr.

2.2 Capital Investments

The forecast of BPA's capital investments for FY 2024-2025 used to develop the BP-24 transmission final proposal rates was published in the IPR closeout reports. The following section describes the capital investment forecasts.

BPA transmission capital spending projections including allowance for funds used during construction (AFUDC) for the FY 2024-2025 rate period are $1.132 billion. These investments are:

- Transmission programs ($1.089 billion)
- Environmental program ($12.5 million)
- Corporate capital program ($29.9 million)

Transmission Revenue Requirement Study Documentation, BP-24-FS-BPA-06A, Table 7-2.

2.2.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be the primary source of capital used to finance projected FY 2024-2025 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.

2.2.2 Federal Appropriations

All Congressional Appropriations related to the Transmission system have been fully repaid. As a result, the repayment study no longer includes any obligation to repay appropriations.

2.2.3 Revenues for Capital Investment

The revenue requirement assumes that $55 million per year of the capital program is funded with current revenues. This revenue financing was added consistent with the Sustainable Capital Financing Policy adopted in August 2022.

2.2.4 Non-Federal Payment Obligations

The transmission revenue requirements reflect two forms of non-Federal payment obligations. The first is lease purchase arrangements for assets. BPA entered into its first 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. Since the completion of the Schultz-Wautoma project, BPA has entered into additional lease financing arrangements with NIFC, Port of Morrow, and Idaho Energy Resources Authority. BPA constructs the facilities financed by the lease holder and makes periodic lease payments. During the term of the lease, BPA operates the facilities. At the end of the lease, BPA has an option to purchase the facilities for a nominal fee. The revenue requirement includes all transactions BPA expects to complete by the date of the Final Proposal. BPA does not currently anticipate entering into new lease purchase arrangements in the rate period.

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.

2.2.5 Customer-Financed Projects

The revenue requirements also reflect the impacts of customer-financed projects. Customers have financed capital construction projects 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.

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 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.

2.3 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 a transmission system plant.

In conducting the repayment studies, BPA includes as fixed inputs the annual debt service payments associated with its non-Federal 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. Forecast transmission repayment obligations related to the lease purchase program are also modeled and 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. Projected lease purchase obligations assumed in the repayment study are held to the same parameters.

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 five-year period. Generally bonds are issued with a provision that allows the bonds to be called any time. Bonds also may be issued with provisions such as a five-year call or a no 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-24-FS-BPA-06A, Ch. 12.

2.4 Change to Plant and Debt Assumptions

The revenue requirement study includes a forecast of the Grand Coulee switchyard transfer anticipated to be completed in FY 2023, when Reclamation will transfer ownership of switchyard assets located at the Grand Coulee dam to BPA. The assets, with a net book value of approximately $124 million, are currently part of Power's asset base. The assets will be functionalized to Transmission. BPA will also transfer debt, estimated to be $109 million, from Power to Transmission. The amount of debt will be equal to the net book value multiplied by Power's debt-to-asset ratio.

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 PNRR and, if necessary, an MRNR component. The Statement of Cash Flows shows the analysis used to determine MRNR and the cash available for risk mitigation.

The Income Statement (Table 3) displays the components of the annual revenue requirements, which include total operating expenses (line 9), net interest expense (line 23), MRNR (line 27), and PNRR (line 28). The sum of these four major components is the total revenue requirement (line 31) for each year of the rate period. (Note: all tables referenced in this section are located at the back of this document.)

The MRNR (Table 3, line 27) results from an analysis of the Statement of Cash Flows (Table 4). MRNR may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the transmission repayment studies.

The Statement of Cash Flows (Table 4) analyzes annual cash inflows and outflows. Cash provided by current operations (line 11), driven by expenses not requiring cash and non-cash revenues, shown in lines 3 through 10, must be sufficient to compensate for the difference between cash used for capital investments (line 16) and cash from Treasury borrowing (line 24). If cash provided by current operations is not sufficient, MRNR (line 2) must be included in revenue requirements to accommodate the shortfall, yielding at least a zero annual increase in cash (line 26). The MRNR amount shown on the Statement of Cash Flows (line 2) then is incorporated in the Income Statement (Table 3, line 27).

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 2024-2025 rate period and the ensuing repayment period. For revenue at current rates, *see* Transmission Revenue Requirement Study Documentation, BP-24-FS-BPA-06A, Ch. 13.

The result of the current revenue test demonstrates that projected revenue from current rates, without the proposed application of financial reserves from the FY 2022 Transmission Reserves Distribution Clause and implementation of the BP-24 Rates Settlement, is inadequate to meet the cost recovery criteria of Order RA 6120.2 because the net position is negative in the rate period and for some years of the repayment period. *See* Table 7, column K.

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 developed consistent with the FY 2022 Transmssion Reserves Distribution Clause proposal and the terms of the BP-24 Rates Settlement will meet cost recovery requirements for the rate period. The revised revenue test is conducted using the forecast of revenue under proposed rates. Transmission Revenue Requirement Study Documentation, BP-24-FS-BPA-06A, Ch. 13.

The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill the basic cost recovery requirements for the rate period, FY 2024-2025. For the rate period, the demonstration of the adequacy of proposed rates is shown in Tables 8 and 9 of this study. 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 (or 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.

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

This page intentionally left blank.

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

		A	B	C
		2024	2025	Rate Period Average
1	PROJECTED REVENUES FROM PROPOSED RATES	1,253,300	1,275,142	1,264,221
2	PROJECTED EXPENSES	1,198,642	1,220,570	1,209,606
3	NET REVENUES	54,658	54,572	54,615

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

		A	B	C
		BOND AMORTIZATION	APPROPRIATIONS AMORTIZATION	TOTAL
1	2024	205,012	-	205,012
2	2025	187,438	-	187,438
3	TOTAL	392,450	-	392,450

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

		A 2024	B 2025
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	191,615	198,324
3	TRANSMISSION ENGINEERING	60,231	61,194
4	TRANSMISSION MAINTENANCE INCLUDING ENVIRONMENT	193,212	199,230
5	TRANSMISSION ACQ & ANCILLARY SERVICES	117,998	117,998
6	BPA INTERNAL SUPPORT	136,034	139,965
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
8	DEPRECIATION & AMORTIZATION	357,998	343,958
9	TOTAL OPERATING EXPENSES	1,057,089	1,060,670
10			
11			
12	INTEREST EXPENSE		
13	INTEREST EXPENSE		
14	FEDERAL APPROPRIATIONS	-	-
15	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
16	ON LONG-TERM DEBT	123,338	139,964
17	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
18	DEBT SERVICE REASSIGNMENT INTEREST	843	-
19	NON-FEDERAL INTEREST (INCL CUSTOMER FUNDED)	61,885	62,050
20	PREMIUMS/DISCOUNTS	-	-
21	AFUDC	(15,100)	(13,934)
22	INTEREST INCOME	(1,804)	(2,575)
23	NET INTEREST EXPENSE	150,752	167,096
24			
25	TOTAL EXPENSES	1,207,841	1,227,766
26			
27	TOTAL MINIMUM REQUIRED NET REVENUE 1/	54,751	54,723
28	PLANNED NET REVENUES FOR RISK	-	-
29	TOTAL PLANNED NET REVENUE	54,751	54,723
30			
31	TOTAL REVENUE REQUIREMENT	1,262,593	1,282,490

1/ See note on cash flow table

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

		A 2024	B 2025
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUE	54,751	54,723
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	357,998	343,958
5	CUSTOMER FUNDED PROJECTS NET INTEREST	3,656	2,918
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	NON-CASH REVENUES		
9	CUSTOMER FUNDED	(24,112)	(26,502)
10	AC INTERTIE CO/FIBER	(3,791)	(3,524)
11	CASH PROVIDED BY CURRENT OPERATIONS	370,093	353,164
12			
13	CASH USED FOR CAPITAL INVESTMENTS:		
14	INVESTMENT IN:		
15	UTILITY PLANT	(573,492)	(557,985)
16	CASH USED FOR CAPITAL INVESTMENTS	(573,492)	(557,985)
17			
18	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
19	INCREASE IN LONG-TERM DEBT	518,492	502,985
20	DEBT SERVICE REASSIGNMENT PRINCIPAL	(17,640)	-
21	REPAYMENT OF CAPITAL LEASES	(92,441)	(110,726)
22	REPAYMENT OF LONG-TERM DEBT	(205,012)	(187,438)
23	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-
24	CASH FROM TREASURY BORROWING AND APPROP.	203,399	204,821
25			
26	ANNUAL INCREASE (DECREASE) IN CASH	-	-
27	PLANNED NET REVENUES FOR RISK	-	-
28	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: Transmission Current Revenue Test Income Statement

($000s)

		A 2024	B 2025
1	REVENUES FROM CURRENT RATES	1,246,362	1,270,570
2			
3	OPERATING EXPENSES		
4	TRANSMISSION OPERATIONS	191,615	198,324
5	TRANSMISSION ENGINEERING	60,231	61,194
6	TRANSMISSION MAINTENANCE	193,212	199,230
7	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	117,998	117,998
8	BPA INTERNAL SUPPORT	136,034	139,965
9	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
10	DEPRECIATION & AMORTIZATION	357,998	343,958
11	TOTAL OPERATING EXPENSES	1,057,089	1,060,670
12			
13	INTEREST EXPENSE		
14	INTEREST EXPENSE		
15	FEDERAL APPROPRIATIONS	-	-
16	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
17	ON LONG-TERM DEBT	123,338	139,964
18	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
19	DEBT SERVICE REASSIGNMENT INTEREST	843	-
20	NON-FEDERAL INTEREST	61,885	62,050
21	PREMIUMS/DISCOUNTS	-	-
22	AFUDC	(15,100)	(13,934)
23	INTEREST INCOME	(1,889)	(2,614)
24	NET INTEREST EXPENSE	150,667	167,057
25			
26	TOTAL EXPENSES	1,207,757	1,227,727
27			
28	NET REVENUES	38,605	42,843

Table 6: Transmission Current Revenue Test Statement of Cash Flows

($000s)

		A 2024	B 2025
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	38,605	42,843
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	-	-
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	357,998	343,958
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	3,656	2,918
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(24,112)	(26,502)
11	AC INTERTIE CO/FIBER	(3,791)	(3,524)
12	CASH PROVIDED BY CURRENT OPERATIONS	353,947	341,284
13			
14	CASH USED FOR CAPITAL INVESTMENTS:		
15	INVESTMENT IN:		
16	UTILITY PLANT	(573,492)	(557,985)
17	CASH USED FOR CAPITAL INVESTMENTS	(573,492)	(557,985)
18			
19	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
20	INCREASE IN LONG-TERM DEBT	518,492	502,985
21	DEBT SERVICE REASSIGNMENT PRINCIPAL	(17,640)	-
22	REPAYMENT OF CAPITAL LEASES	(92,441)	(110,726)
23	REPAYMENT OF LONG-TERM DEBT	(205,012)	(187,438)
24	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-
25	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	203,399	204,821
26			
27	ANNUAL INCREASE (DECREASE) IN CASH	(16,146)	(11,880)

Table 7: Transmission Revenues from Current Rates – Results through the Repayment Period ($000s)

		A	B	C	D	E	F
	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)**
1	**Thru 2017**	27,114,903	12,239,189	348,748	6,224,662	6,914,738	1,387,566
2							
3	**2018**	1,090,198	596,563	-	286,284	140,788	66,563
4	**2019**	1,039,877	597,226	-	305,720	147,600	(10,669)
5	**2020**	1,094,215	612,982	-	339,833	148,894	(7,494)
6	**2021**	1,107,889	631,300	-	338,371	135,657	2,561
7	**2022**	1,249,958	662,229	-	338,768	140,625	108,336
8							
9	**COST EVALUATION**						
10	**PERIOD**						
11	**2023**	1,151,547	623,509	-	349,991	144,815	33,232
12							
13	**RATE APPROVAL**						
14	**PERIOD**						
15	**2024**	1,246,362	699,091	-	357,998	150,667	38,605
16	**2025**	1,270,570	716,712	-	343,958	167,057	42,843
17							
18	**REPAYMENT**						
19	**PERIOD**						
20	**2026**	1,270,570	716,712	(9,275)	343,958	177,801	41,374
21	**2027**	1,270,570	716,712	(9,275)	343,958	175,027	44,148
22	**2028**	1,270,570	716,712	(9,275)	343,958	171,534	47,641
23	**2029**	1,270,570	716,712	(9,275)	343,958	167,801	51,374
24	**2030**	1,270,570	716,712	(9,275)	343,958	162,321	56,854
25	**2031**	1,270,570	716,712	(9,275)	343,958	158,755	60,420
26	**2032**	1,270,570	716,712	(9,275)	343,958	154,059	65,116
27	**2033**	1,270,570	716,712	(9,275)	343,958	152,473	66,702
28	**2034**	1,270,570	716,712	(9,275)	343,958	148,510	70,665
29	**2035**	1,270,570	716,712	(9,275)	343,958	148,271	70,904
30	**2036**	1,270,570	716,712	(9,275)	343,958	147,190	71,985
31	**2037**	1,270,570	716,712	(9,275)	343,958	144,681	74,493
32	**2038**	1,270,570	716,712	(9,275)	343,958	142,743	76,432
33	**2039**	1,270,570	716,712	(9,275)	343,958	141,357	77,818
34	**2040**	1,270,570	716,712	(9,275)	343,958	140,239	78,936
35	**2041**	1,270,570	716,712	(9,275)	343,958	140,098	79,077
36	**2042**	1,270,570	716,712	(9,275)	343,958	138,577	80,598
37	**2043**	1,270,570	716,712	(9,275)	343,958	135,974	83,201
38	**2044**	1,270,570	716,712	(9,275)	343,958	136,359	82,816
39	**2045**	1,270,570	716,712	(9,275)	343,958	136,073	83,102
40	**2046**	1,270,570	716,712	(9,275)	343,958	136,031	83,144
41	**2047**	1,270,570	716,712	(9,275)	343,958	133,116	86,059
42	**2048**	1,270,570	716,712	(9,275)	343,958	127,801	91,374
43	**2049**	1,270,570	716,712	(9,275)	343,958	123,296	95,878
44	**2050**	1,270,570	716,712	(9,275)	343,958	118,626	100,549
45	**2051**	1,270,570	716,712	(9,275)	343,958	113,783	105,392
46	**2052**	1,270,570	716,712	(9,275)	343,958	108,761	110,414
47	**2053**	1,270,570	716,712	(9,275)	343,958	103,553	115,621
48	**2054**	1,270,570	716,712	(9,275)	343,958	98,154	121,021
49	**2055**	1,270,570	716,712	(9,275)	343,958	92,554	126,621
50	**2056**	1,270,570	716,712	(9,275)	343,958	86,748	132,427
51	**2057**	1,270,570	716,712	(9,275)	343,958	80,727	138,448
52	**2058**	1,270,570	716,712	(9,275)	343,958	74,483	144,692
53	**2059**	1,270,570	716,712	(9,275)	343,958	68,008	151,167
54	**2060**	1,270,570	716,712	(9,275)	343,958	61,318	157,857
55							
56	**TRANSMISSION**						
57	**TOTALS**	80,835,465	42,463,704	24,137	20,924,117	12,637,924	4,785,583

Table 7 (continued)

		G	H	I	J	K
		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)
1	**Thru 2017**	5,764,188	8,338,469	6,915,652	974,995	447,821
2						
3	**2018**	272,676	316,185	47,906	193,402	74,877
4	**2019**	6,461	(4,208)	235,016	17,304	(256,527)
5	**2020**	297,230	289,736	199,900	98,999	(9,163)
6	**2021**	317,907	320,467	284,700	99,352	(63,585)
7	**2022**	263,268	371,604	214,900	98,296	58,408
8						
9	**COST EVALUATION**					
10	**PERIOD**					
11	**2023**	313,096	306,328	209,379	96,373	576
12						
13	**RATE APPROVAL**					
14	**PERIOD**					
15	**2024**	315,342	298,947	205,012	110,081	(16,146)
16	**2025**	298,441	286,284	187,438	110,726	(11,880)
17						
18	**REPAYMENT**					
19	**PERIOD**					
20	**2026**	298,441	339,815	180,519	111,344	47,952
21	**2027**	298,441	342,589	205,646	88,851	48,092
22	**2028**	298,441	346,082	204,442	78,077	63,563
23	**2029**	298,441	349,815	284,623	3,094	62,098
24	**2030**	298,441	355,295	296,877	3,194	55,224
25	**2031**	298,441	358,861	303,308	3,270	52,283
26	**2032**	298,441	363,557	310,906	3,115	49,536
27	**2033**	298,441	365,143	317,179	3,267	44,697
28	**2034**	298,441	369,106	219,347	104,891	44,868
29	**2035**	298,441	369,345	196,347	128,423	44,575
30	**2036**	298,441	370,426	197,456	128,589	44,381
31	**2037**	298,441	372,934	232,375	98,179	42,380
32	**2038**	298,441	374,873	232,262	98,050	44,561
33	**2039**	298,441	376,259	233,100	98,240	44,919
34	**2040**	298,441	377,377	234,609	98,412	44,356
35	**2041**	298,441	377,518	226,510	106,525	44,483
36	**2042**	298,441	379,039	245,761	88,854	44,424
37	**2043**	298,441	381,642	235,337	104,052	42,253
38	**2044**	298,441	381,257	238,845	105,505	36,906
39	**2045**	298,441	381,543	239,710	104,961	36,872
40	**2046**	298,441	381,585	233,074	105,065	43,445
41	**2047**	298,441	384,500	257,024	83,086	44,391
42	**2048**	298,441	389,815	343,441	2,202	44,171
43	**2049**	298,441	394,319	347,828	2,325	44,166
44	**2050**	298,441	398,990	352,375	2,455	44,160
45	**2051**	298,441	403,833	357,087	2,593	44,154
46	**2052**	298,441	408,855	361,970	2,737	44,148
47	**2053**	298,441	414,062	367,031	2,890	44,141
48	**2054**	298,441	419,462	372,276	3,052	44,135
49	**2055**	298,441	425,062	377,711	3,222	44,128
50	**2056**	298,441	430,868	383,345	3,402	44,121
51	**2057**	298,441	436,889	389,183	3,593	44,113
52	**2058**	298,441	443,133	395,234	3,793	44,105
53	**2059**	298,441	449,608	401,505	4,005	44,097
54	**2060**	298,441	456,298	411,494	723	44,080
55						
56	**TRANSMISSION**					
57	**TOTALS**	18,294,041	24,093,285	18,685,640	3,583,568	1,824,077

1/ Consists of depreciation plus other non-cash expenses and other adjustments and any accounting write-offs included in expenses. Also removed revenue financing. FY 2019 includes a one-time decrease of $182 million to rebalance financial reserves between the transmission and generation functions to correct for a misallocation error in the calculation of financial reserves attributed to the business units.

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

		A 2024	B 2025
1	REVENUES FROM PROPOSED RATES	1,253,300	1,275,142
2			
3	OPERATING EXPENSES		
4	TRANSMISSION OPERATIONS	191,615	198,324
5	TRANSMISSION ENGINEERING	60,231	61,194
6	TRANSMISSION MAINTENANCE	193,212	199,230
7	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	117,998	117,998
8	BPA INTERNAL SUPPORT	136,034	139,965
9	OTHER INCOME, EXPENSES & ADJUSTMENTS	(9,200)	(7,200)
10	DEPRECIATION & AMORTIZATION	357,998	343,958
11	TOTAL OPERATING EXPENSES	1,047,889	1,053,470
12			
13	INTEREST EXPENSE		
14	INTEREST EXPENSE		
15	FEDERAL APPROPRIATIONS	-	-
16	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
17	ON LONG-TERM DEBT	123,338	139,964
18	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
19	DEBT SERVICE REASSIGNMENT INTEREST	843	-
20	NON-FEDERAL INTEREST	61,885	62,050
21	PREMIUMS/DISCOUNTS	-	-
22	AFUDC	(15,100)	(13,934)
23	INTEREST INCOME	(1,920)	(2,734)
24	NET INTEREST EXPENSE	150,636	166,937
25			
26	TOTAL EXPENSES	1,198,525	1,220,406
27			
28	NET REVENUES	54,775	54,736

Table 9: Transmission Revised Revenue Test Statement of Cash Flows

($000s)

		A 2024	B 2025
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	54,775	54,736
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	-	-
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	357,998	343,958
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	3,656	2,918
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(24,112)	(26,502)
11	AC INTERTIE CO/FIBER	(3,791)	(3,524)
12	CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION		
13	CASH PROVIDED BY CURRENT OPERATIONS	370,117	353,176
14			
15	CASH USED FOR CAPITAL INVESTMENTS:		
16	INVESTMENT IN:		
17	UTILITY PLANT	(573,492)	(557,985)
18	CASH USED FOR CAPITAL INVESTMENTS	(573,492)	(557,985)
19			
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
21	INCREASE IN LONG-TERM DEBT	518,492	502,985
22	DEBT SERVICE REASSIGNMENT PRINCIPAL	(17,640)	-
23	REPAYMENT OF CAPITAL LEASES	(92,441)	(110,726)
24	REPAYMENT OF LONG-TERM DEBT	(205,012)	(187,438)
25	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-
26	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	203,399	204,821
27			
28	ANNUAL INCREASE (DECREASE) IN CASH	23	12

Table 10: Transmission Revenues from Proposed Rates through the Repayment Period

($000s)

	A	B	C	D	E	F
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)
Thru 2017	27,114,903	12,239,189	348,748	6,224,662	6,914,738	1,387,566
2018	1,090,198	596,563		286,284	140,788	66,563
2019	1,039,877	597,226	-	305,720	147,600	(10,668)
2020	1,094,215	612,982	-	339,833	148,894	(7,494)
2021	1,107,889	631,300	-	338,371	135,657	2,561
2022	1,249,958	662,229		338,768	140,625	108,336
COST EVALUATION						
PERIOD						
2023	1,151,547	623,509	-	349,991	144,815	33,232
RATE APPROVAL						
PERIOD						
2024	1,253,300	689,891	-	357,998	150,636	54,775
2025	1,275,142	709,512	-	343,958	166,937	54,736
REPAYMENT						
PERIOD						
2026	1,275,142	709,512	(9,275)	343,958	177,801	53,146
2027	1,275,142	709,512	(9,275)	343,958	175,027	55,920
2028	1,275,142	709,512	(9,275)	343,958	171,534	59,413
2029	1,275,142	709,512	(9,275)	343,958	167,801	63,146
2030	1,275,142	709,512	(9,275)	343,958	162,321	68,626
2031	1,275,142	709,512	(9,275)	343,958	158,755	72,192
2032	1,275,142	709,512	(9,275)	343,958	154,059	76,888
2033	1,275,142	709,512	(9,275)	343,958	152,473	78,474
2034	1,275,142	709,512	(9,275)	343,958	148,510	82,437
2035	1,275,142	709,512	(9,275)	343,958	148,271	82,676
2036	1,275,142	709,512	(9,275)	343,958	147,190	83,757
2037	1,275,142	709,512	(9,275)	343,958	144,681	86,265
2038	1,275,142	709,512	(9,275)	343,958	142,743	88,204
2039	1,275,142	709,512	(9,275)	343,958	141,357	89,590
2040	1,275,142	709,512	(9,275)	343,958	140,239	90,708
2041	1,275,142	709,512	(9,275)	343,958	140,098	90,849
2042	1,275,142	709,512	(9,275)	343,958	138,577	92,370
2043	1,275,142	709,512	(9,275)	343,958	135,974	94,973
2044	1,275,142	709,512	(9,275)	343,958	136,359	94,588
2045	1,275,142	709,512	(9,275)	343,958	136,073	94,874
2046	1,275,142	709,512	(9,275)	343,958	136,031	94,916
2047	1,275,142	709,512	(9,275)	343,958	133,116	97,831
2048	1,275,142	709,512	(9,275)	343,958	127,801	103,146
2049	1,275,142	709,512	(9,275)	343,958	123,296	107,650
2050	1,275,142	709,512	(9,275)	343,958	118,626	112,321
2051	1,275,142	709,512	(9,275)	343,958	113,783	117,164
2052	1,275,142	709,512	(9,275)	343,958	108,761	122,186
2053	1,275,142	709,512	(9,275)	343,958	103,553	127,394
2054	1,275,142	709,512	(9,275)	343,958	98,154	132,793
2055	1,275,142	709,512	(9,275)	343,958	92,554	138,393
2056	1,275,142	709,512	(9,275)	343,958	86,748	144,199
2057	1,275,142	709,512	(9,275)	343,958	80,727	150,220
2058	1,275,142	709,512	(9,275)	343,958	74,483	156,464
2059	1,275,142	709,512	(9,275)	343,958	68,008	162,939
2060	1,275,142	709,512	(9,275)	343,958	61,318	169,629
TRANSMISSION						
TOTALS	81,006,996	42,195,304	24,137	20,924,117	12,637,772	5,225,666

Table 10 (continued)

	YEAR	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	J NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	K NET POSITION (K=H-I-J)
1	**Thru 2017**	5,764,188	8,338,469	6,915,652	974,995	447,821
3	**2018**	272,676	316,185	47,906	193,402	74,877
4	**2019**	6,461	(4,207)	235,016	17,304	(256,526)
5	**2020**	297,230	289,736	199,900	98,999	(9,163)
6	**2021**	317,907	320,467	284,700	99,352	(63,585)
7	**2022**	263,268	371,604	214,900	98,296	58,408
	COST EVALUATION PERIOD					
11	**2023**	313,096	306,328	209,379	96,373	576
	RATE APPROVAL PERIOD					
15	**2024**	315,342	315,117	205,012	110,081	23
16	**2025**	298,441	298,176	187,438	110,726	12
	REPAYMENT PERIOD					
20	**2026**	298,441	351,587	180,519	111,344	59,724
21	**2027**	298,441	354,361	205,646	88,851	59,864
22	**2028**	298,441	357,854	204,442	78,077	75,336
23	**2029**	298,441	361,587	284,623	3,094	73,870
24	**2030**	298,441	367,067	296,877	3,194	66,996
25	**2031**	298,441	370,633	303,308	3,270	64,055
26	**2032**	298,441	375,329	310,906	3,115	61,308
27	**2033**	298,441	376,915	317,179	3,267	56,469
28	**2034**	298,441	380,878	219,347	104,891	56,640
29	**2035**	298,441	381,117	196,347	128,423	56,347
30	**2036**	298,441	382,198	197,456	128,589	56,153
31	**2037**	298,441	384,706	232,375	98,179	54,152
32	**2038**	298,441	386,645	232,262	98,050	56,333
33	**2039**	298,441	388,031	233,100	98,240	56,691
34	**2040**	298,441	389,149	234,609	98,412	56,128
35	**2041**	298,441	389,290	226,510	106,525	56,255
36	**2042**	298,441	390,811	245,761	88,854	56,196
37	**2043**	298,441	393,414	235,337	104,052	54,025
38	**2044**	298,441	393,029	238,845	105,505	48,679
39	**2045**	298,441	393,315	239,710	104,961	48,644
40	**2046**	298,441	393,357	233,074	105,065	55,217
41	**2047**	298,441	396,272	257,024	83,086	56,163
42	**2048**	298,441	401,587	343,441	2,202	55,943
43	**2049**	298,441	406,091	347,828	2,325	55,938
44	**2050**	298,441	410,762	352,375	2,455	55,932
45	**2051**	298,441	415,605	357,087	2,593	55,926
46	**2052**	298,441	420,627	361,970	2,737	55,920
47	**2053**	298,441	425,834	367,031	2,890	55,913
48	**2054**	298,441	431,234	372,276	3,052	55,907
49	**2055**	298,441	436,834	377,711	3,222	55,900
50	**2056**	298,441	442,640	383,345	3,402	55,893
51	**2057**	298,441	448,661	389,183	3,593	55,885
52	**2058**	298,441	454,905	395,234	3,793	55,877
53	**2059**	298,441	461,380	401,505	4,005	55,869
54	**2060**	298,441	468,070	411,494	723	55,852
57	**TRANSMISSION TOTALS**	18,294,041	24,533,368	18,685,640	3,583,568	2,264,160

1/ Consists of depreciation plus other non-cash expenses and other adjustments and any accounting write-offs included in expenses. Also removed revenue financing. FY 2019 includes a one-time decrease of $182 million to rebalance financial reserves between the transmission and generation functions to correct for a misallocation error in the calculation of financial reserves attributed to the business units.

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2023	15,684,798	-	15,684,798	144,000	65,379	4,222,161	7,941,683
2	2024	518,001	-	16,202,799	205,012	-	4,535,150	8,254,672
3	2025	603,000	-	16,805,799	187,438	-	4,950,712	8,670,234
4	2026	-	222,840	17,028,639	125,000	55,519	4,993,033	8,768,074
5	2027	-	222,840	17,251,479	122,000	83,646	5,010,227	8,868,914
6	2028	-	222,840	17,474,319	70,456	133,985	5,028,626	8,815,954
7	2029	-	222,840	17,697,159	110,000	174,623	4,966,842	8,928,794
8	2030	-	222,840	17,919,999	133,896	162,981	4,892,806	9,017,738
9	2031	-	222,840	18,142,839	76,000	227,308	4,812,338	9,164,578
10	2032	-	222,840	18,365,679	-	310,906	4,724,272	9,288,518
11	2033	-	222,840	18,588,519	59,000	258,179	4,629,933	9,412,358
12	2034	-	222,840	18,811,359	82,300	137,047	4,633,426	9,469,898
13	2035	-	222,840	19,034,199	24,000	172,347	4,659,919	9,523,738
14	2036	-	222,840	19,257,039	29,000	168,456	4,685,303	9,492,578
15	2037	-	222,840	19,479,879	112,940	119,435	4,675,768	9,591,478
16	2038	-	222,840	19,702,719	50,000	182,262	4,666,346	9,709,318
17	2039	-	222,840	19,925,559	90,000	143,100	4,656,086	9,767,158
18	2040	-	222,840	20,148,399	70,000	164,609	4,644,317	9,847,749
19	2041	-	222,840	20,371,239	94,000	132,510	4,640,646	9,940,589
20	2042	-	222,840	20,594,079	109,000	136,761	4,617,726	10,040,429
21	2043	-	222,840	20,816,919	77,000	158,337	4,605,229	10,124,269
22	2044	-	222,840	21,039,759	39,000	199,845	4,589,224	10,214,109
23	2045	-	222,840	21,262,599	19,000	220,710	4,572,354	10,300,949
24	2046	-	222,840	21,485,439	57,000	176,074	4,562,120	10,363,789
25	2047	-	222,840	21,708,279	-	257,024	4,527,936	10,432,629
26	2048	-	222,840	21,931,119	-	343,441	4,407,335	10,470,469
27	2049	-	222,840	22,153,959	-	347,828	4,282,346	10,549,509
28	2050	-	222,840	22,376,799	-	352,375	4,152,812	10,624,561
29	2051		222,840	22,599,639	-	357,087	4,018,565	10,681,734
30	2052	-	222,840	22,822,479	-	361,970	3,879,435	10,642,574
31	2053	-	222,840	23,045,319	-	367,031	3,735,245	10,464,997
32	2054	-	222,840	23,268,159	-	372,276	3,585,809	10,441,837
33	2055	-	222,840	23,490,999	-	377,711	3,430,937	10,343,343
34	2056	-	222,840	23,713,839	-	383,345	3,270,432	10,566,183
35	2057	-	222,840	23,936,679	-	389,183	3,104,089	10,789,023
36	2058	-	222,840	24,159,519	-	395,234	2,931,695	11,011,863
37	2059	-	222,840	24,382,359	-	401,505	2,753,030	11,234,703
38	2060	-	222,840	24,605,199	-	411,494	2,564,375	11,457,543
39		**$16,805,799**	**$7,799,400**		**$2,086,043**	**$8,701,523**		

BONNEVILLE POWER ADMINISTRATION
DOE/BP-5248 • July 2023