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-22 Rate Proceeding

Final Proposal

Transmission Revenue Requirement Study

BP-22-FS-BPA-09

July 2021

TRANSMISSION REVENUE REQUIREMENT STUDY

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FIGURES AND TABLES

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
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
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
ELMP	Extended Locational Marginal Pricing
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)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
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
KSI	key strategic initiative
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
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
NWPP	Northwest Power Pool
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)
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
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
USACE	U.S. Army Corps of Engineers
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
WSPP	Western Systems Power Pool

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1. INTRODUCTION

1.1 Purpose of the Study

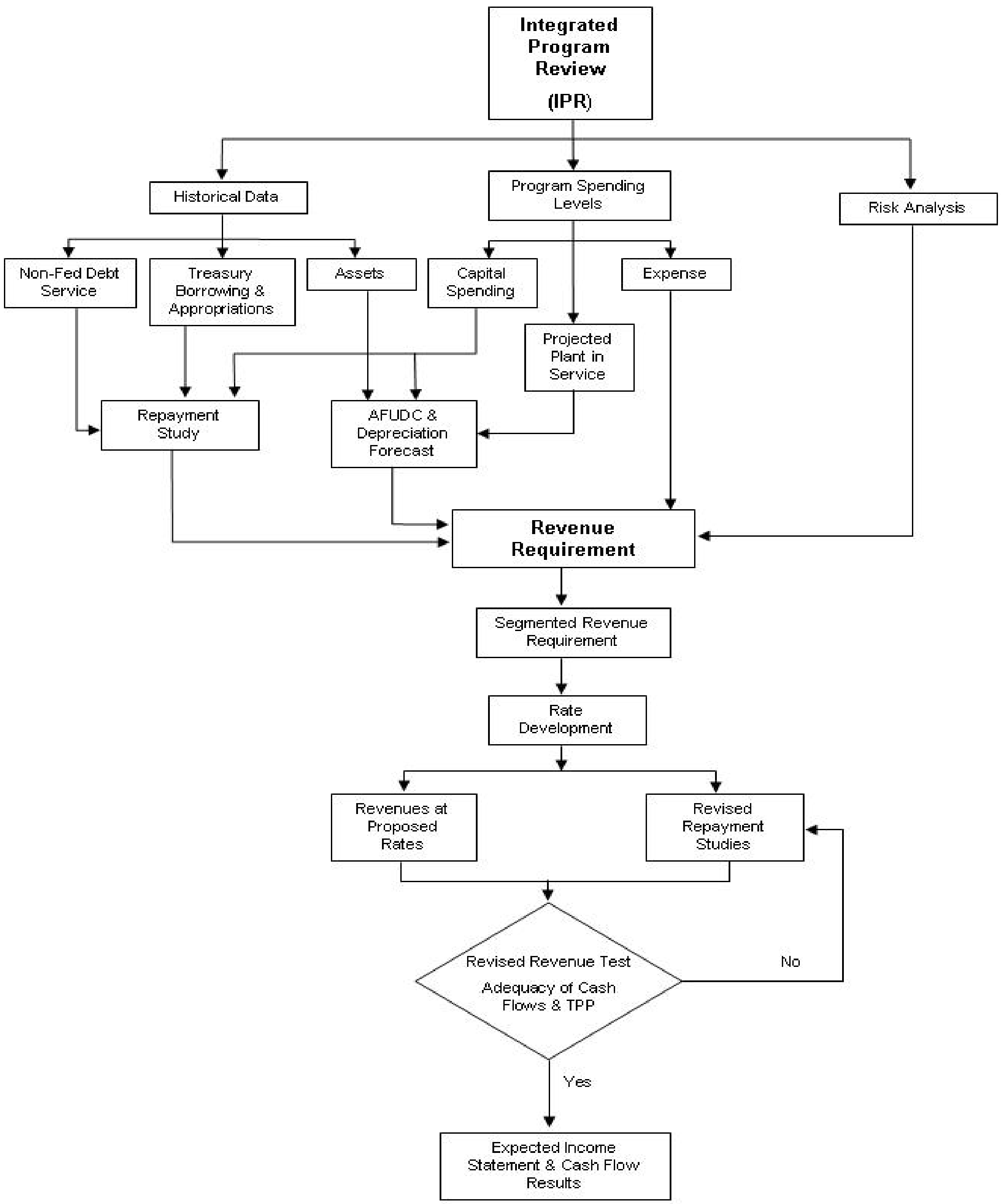
The purpose of the Transmission Revenue Requirement Study is to establish the revenues from transmission and ancillary services that are necessary to recover, in accordance with sound business principles, the Federal Columbia River Transmission System (FCRTS) costs associated with the transmission of 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 final proposal filing includes Fiscal Year (FY) 2021 and the proposed rate period, FY 2022–2023. 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-22-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-22-FS-BPA-09A, 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 the Power and Transmission Risk Study, BP-22-FS-BPA-05. From these three steps, the revenue requirement is set at the level necessary to fulfill cost recovery requirements and objectives. This process is depicted in Figure 1, below. Once the revenue requirement is completed, it is segmented and passed to the rate development process, where it is used to develop rates.

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. 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 the Power and Transmission Risk Study, BP-22-FS-BPA-05, § 5.2.4.2.

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed transmission rates for FY 2022–2023. 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

> [t]he 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 2022-23 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 2022–2023.

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, 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.* 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. 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.

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 2022-2023 rate period it began on June 15, 2020, when BPA hosted the first 2020 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 2020 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' proposed expense and capital spending levels for FY 2022-2023. The opening workshop launched a public comment period, providing participants the opportunity to provide feedback on the proposed spending levels. The initial publication and workshop described the drivers, goals, and risks associated with the proposed expense and capital spending levels; and made comparisons to the last rate case.

Following the opening workshop, BPA held a series of workshops to discuss spending levels for the program areas, including the Chief Administrative Office, Information Technology, Federal Hydro, Columbia Generating Station, Environment Fish and Wildlife, Energy Efficiency, and Transmission. While debt management actions are outside the scope of the IPR process, a workshop was held to enhance participants' understanding of the implications of past debt management decisions, proposed capital spending, and potential debt management tools. This includes forecasts of net interest expense and depreciation and amortization expense, which includes amortization of the terminated I-5 reinforcement project.

After considering the comments received, BPA released a final IPR closeout report in September 2020.

BPA conducted an IPR 2 process in March 2021 to review the Transmission capital spending program. BPA also reviewed the previous IPR spending forecasts for fish and wildlife mitigation in light of the Columbia River System Operation Environmental Impact Statement and BPA's proposal to discontinue regulatory asset treatment of studies funded through the Columbia River Fish Mitigation program. A closeout report was issued in April 2021.

This study incorporates the spending levels identified in the 2020 IPR and the IPR 2 closeout reports, which can be found on BPA's public website: https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2020.aspx

2.2 Capital Investments

The forecast of BPA's capital investments for FY 2022-2023 used to develop the BP-22 transmission final proposal rates was published in the IPR and IPR2 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 2022–2023 rate period are $960 million. Rounded, these investments are:

- Transmission programs ($902 million)
- Environmental program ($13.6 million)
- Corporate capital program ($44.5 million)

Transmission Revenue Requirement Study Documentation, BP-22-FS-BPA-09A, 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 2022-2023 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 $40 million per year of the capital program is funded with current revenues as described in the settlement agreement. It was not necessary to add revenue financing due to the Leverage Policy.

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 (Schultz-Wautoma 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. BPA 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 transmission system plant (45 years).

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-22-FS-BPA-09A, Ch. 12.

2.4 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, BP-22-FS-BPA-07

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, a 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.

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 2022–2023 rate period and the ensuing repayment period. For revenue at current rates, *see* Transmission Rate Study and Documentation, BP-22-FS-BPA-08, 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 because the net position is negative in the rate period and for some years of the repayment period. *See* Table 7, column K. This means that current rates could not be extended.

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 Rate Study and Documentation, BP-22-FS-BPA-08, 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 (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.

The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill cost recovery requirements for the rate period, FY 2022-2023. 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

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

		A	B	C
		2022	2023	Rate Period Average
1	PROJECTED REVENUES FROM PROPOSED RATES	1,151,269	1,151,547	1,151,408
2	PROJECTED EXPENSES	1,102,486	1,118,315	1,110,401
3	NET REVENUES	48,783	33,232	41,007

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

		A	B	C
		BOND AMORTIZATION	APPROPRIATIONS AMORTIZATION	TOTAL
1	2022	204,197	-	204,197
2	2023	209,379	-	209,379
3	TOTAL	413,576	-	413,576

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

		A 2022	B 2023
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	169,239	172,135
3	TRANSMISSION ENGINEERING	56,570	57,094
4	TRANSMISSION MAINTENANCE INCLUDING ENVIRONMENT	177,560	179,860
5	TRANSMISSION ACQ & ANCILLARY SERVICES	109,597	110,278
6	BPA INTERNAL SUPPORT	103,195	104,681
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
8	DEPRECIATION & AMORTIZATION	345,303	349,991
9	TOTAL OPERATING EXPENSES	960,936	973,500
10			
11			
12	INTEREST EXPENSE		
13	INTEREST EXPENSE		
14	FEDERAL APPROPRIATIONS	-	-
15	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
16	ON LONG-TERM DEBT	108,189	115,052
17	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
18	DEBT SERVICE REASSIGNMENT INTEREST	2,960	1,927
19	NON-FEDERAL INTEREST (INCL CUSTOMER FUNDED)	67,411	65,176
20	PREMIUMS/DISCOUNTS	-	-
21	AFUDC	(15,937)	(16,016)
22	INTEREST INCOME	(2,002)	(1,810)
23	NET INTEREST EXPENSE	142,210	145,920
24			
25	TOTAL EXPENSES	1,103,146	1,119,420
26			
27	TOTAL MINIMUM REQUIRED NET REVENUE 1/	40,023	40,012
28	PLANNED NET REVENUES FOR RISK	-	-
29	TOTAL PLANNED NET REVENUE	40,023	40,012
30			
31	TOTAL REVENUE REQUIREMENT	1,143,169	1,159,432

1/ See note on cash flow table

Table 4: Transmission Revenue Requirement Statement of Cash Flows

($000s)

		A 2022	B 2023
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUE	40,023	40,012
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	345,303	349,991
5	CUSTOMER FUNDED PROJECTS NET INTEREST	4,304	3,736
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	NON-CASH REVENUES		
9	CUSTOMER FUNDED	(27,442)	(26,071)
10	AC INTERTIE CO/FIBER	(3,507)	(3,507)
11	CASH PROVIDED BY CURRENT OPERATIONS	340,272	345,752
12			
13	CASH USED FOR CAPITAL INVESTMENTS:		
14	INVESTMENT IN:		
15	UTILITY PLANT	(470,870)	(489,393)
16	CASH USED FOR CAPITAL INVESTMENTS	(470,870)	(489,393)
17			
18	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
19	INCREASE IN LONG-TERM DEBT	430,870	449,393
20	DEBT SERVICE REASSIGNMENT PRINCIPAL	(21,596)	(22,678)
21	REPAYMENT OF CAPITAL LEASES	(74,479)	(73,695)
22	REPAYMENT OF LONG-TERM DEBT	(204,197)	(209,379)
23	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-
24	CASH FROM TREASURY BORROWING AND APPROP.	130,598	143,641
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 2022	B 2023
1	REVENUES FROM CURRENT RATES	1,087,493	1,090,365
2			
3	OPERATING EXPENSES		
4	TRANSMISSION OPERATIONS	168,711	171,595
5	TRANSMISSION ENGINEERING	56,570	57,094
6	TRANSMISSION MAINTENANCE	177,560	179,860
7	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	109,597	110,278
8	BPA INTERNAL SUPPORT	103,195	104,681
9	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
10	DEPRECIATION & AMORTIZATION	345,303	349,991
11	TOTAL OPERATING EXPENSES	960,936	973,500
12			
13	INTEREST EXPENSE		
14	INTEREST EXPENSE		
15	FEDERAL APPROPRIATIONS	-	-
16	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
17	ON LONG-TERM DEBT	108,189	115,052
18	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
19	DEBT SERVICE REASSIGNMENT INTEREST	2,960	1,927
20	NON-FEDERAL INTEREST	67,411	65,176
21	PREMIUMS/DISCOUNTS	-	-
22	AFUDC	(15,937)	(16,016)
23	INTEREST INCOME	(2,593)	(2,380)
24	NET INTEREST EXPENSE	141,620	145,350
25			
26	TOTAL EXPENSES	1,102,556	1,118,850
27			
28	NET REVENUES	(15,063)	(28,485)

Table 6: Transmission Current Revenue Test Statement of Cash Flows

($000s)

		A 2020	B 2021
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	(15,063)	(28,485)
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	-	-
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	345,303	349,991
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	4,304	3,736
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(27,442)	(26,071)
11	AC INTERTIE CO/FIBER	(3,507)	(3,507)
12	CASH PROVIDED BY CURRENT OPERATIONS	285,186	277,255
13			
14	CASH USED FOR CAPITAL INVESTMENTS:		
15	INVESTMENT IN:		
16	UTILITY PLANT	(470,870)	(489,393)
17	CASH USED FOR CAPITAL INVESTMENTS	(470,870)	(489,393)
18			
19	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
20	INCREASE IN LONG-TERM DEBT	430,870	449,393
21	DEBT SERVICE REASSIGNMENT PRINCIPAL	(21,596)	(22,678)
22	REPAYMENT OF CAPITAL LEASES	(74,479)	(73,695)
23	REPAYMENT OF LONG-TERM DEBT	(204,197)	(209,379)
24	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-
25	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	130,598	143,641
26			
27	ANNUAL INCREASE (DECREASE) IN CASH	(55,085)	(68,497)

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

($000s)

	YEAR	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C DEBT SERVICE OFFSETS (REV REQ STUDY DOC)	D DEPRECIATION	E NET INTEREST (TABLE D)	F NET REVENUES (F=A-B-C-D-E)
1	**Thru 2015**	24,961,478	11,059,061	348,748	5,719,577	6,638,882	1,195,210
2							
3	**2016**	1,061,700	579,282	-	244,158	136,358	101,902
4	**2017**	1,091,725	600,846	-	260,927	139,499	90,453
5	**2018**	1,090,198	596,563	-	286,284	140,788	66,563
6	**2019**	1,039,877	597,226	-	305,720	147,600	(10,669)
7	**2020**	1,094,215	612,982	-	339,833	148,893	(7,493)
8							
9	**COST EVALUATION**						
10	**PERIOD**						
11	**2021**	1,103,178	635,733	-	342,090	140,694	(15,340)
12							
13	**RATE APPROVAL**						
14	**PERIOD**						
15	**2022**	1,087,493	615,633	-	345,303	141,620	(15,063)
16	**2023**	1,090,365	623,509	-	349,991	145,350	(28,485)
17							
18	**REPAYMENT**						
19	**PERIOD**						
20	**2024**	1,090,365	623,509	(6,897)	349,991	192,489	(68,726)
21	**2025**	1,090,365	623,509	(6,897)	349,991	193,103	(69,341)
22	**2026**	1,090,365	623,509	(6,897)	349,991	186,764	(63,001)
23	**2027**	1,090,365	623,509	(6,897)	349,991	184,203	(60,440)
24	**2028**	1,090,365	623,509	(6,897)	349,991	180,687	(56,924)
25	**2029**	1,090,365	623,509	(6,897)	349,991	178,752	(54,990)
26	**2030**	1,090,365	623,509	(6,897)	349,991	177,372	(53,610)
27	**2031**	1,090,365	623,509	(6,897)	349,991	171,684	(47,921)
28	**2032**	1,090,365	623,509	(6,897)	349,991	163,377	(39,615)
29	**2033**	1,090,365	623,509	(6,897)	349,991	160,594	(36,832)
30	**2034**	1,090,365	623,509	(6,897)	349,991	152,536	(28,773)
31	**2035**	1,090,365	623,509	(6,897)	349,991	147,309	(23,547)
32	**2036**	1,090,365	623,509	(6,897)	349,991	135,460	(11,697)
33	**2037**	1,090,365	623,509	(6,897)	349,991	133,307	(9,545)
34	**2038**	1,090,365	623,509	(6,897)	349,991	119,558	4,205
35	**2039**	1,090,365	623,509	(6,897)	349,991	114,920	8,842
36	**2040**	1,090,365	623,509	(6,897)	349,991	118,009	5,753
37	**2041**	1,090,365	623,509	(6,897)	349,991	119,445	4,318
38	**2042**	1,090,365	623,509	(6,897)	349,991	115,302	8,460
39	**2043**	1,090,365	623,509	(6,897)	349,991	103,954	19,809
40	**2044**	1,090,365	623,509	(6,897)	349,991	94,968	28,795
41	**2045**	1,090,365	623,509	(6,897)	349,991	81,443	42,319
42	**2046**	1,090,365	623,509	(6,897)	349,991	68,635	55,127
43	**2047**	1,090,365	623,509	(6,897)	349,991	55,495	68,268
44	**2048**	1,090,365	623,509	(6,897)	349,991	41,706	82,057
45	**2049**	1,090,365	623,509	(6,897)	349,991	27,197	96,566
46	**2050**	1,090,365	623,509	(6,897)	349,991	11,932	111,831
47	**2051**	1,090,365	623,509	(6,897)	349,991	(4,129)	127,892
48	**2052**	1,090,365	623,509	(6,897)	349,991	(21,027)	144,790
49	**2053**	1,090,365	623,509	(6,897)	349,991	(32,270)	156,033
50	**2054**	1,090,365	623,509	(6,897)	349,991	(34,842)	158,605
51	**2055**	1,090,365	623,509	(6,897)	349,991	(34,842)	158,605
52	**2056**	1,090,365	623,509	(6,897)	349,991	(34,842)	158,605
53	**2057**	1,090,365	623,509	(6,897)	349,991	(34,842)	158,605
54	**2058**	1,090,365	623,509	(6,897)	349,991	(34,842)	158,605
55							
56	**TRANSMISSION**						
57	**TOTALS**	69,704,250	35,720,581	456,086	19,813,703	11,485,281	2,228,598

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 2015**	5,284,623	7,797,648	6,435,803	586,532	775,314
2						
3	**2016**	231,397	333,299	383,410	186,696	(236,807)
4	**2017**	248,168	338,621	96,439	201,768	40,414
5	**2018**	272,676	339,239	47,906	193,402	97,931
6	**2019**	6,461	(4,208)	235,016	17,304	(256,527)
7	**2020**	396,302	388,809	199,900	98,999	89,910
8						
9	**COST EVALUATION**					
10	**PERIOD**					
11	**2021**	322,014	280,232	284,700	99,863	(104,331)
12						
13	**RATE APPROVAL**					
14	**PERIOD**					
15	**2022**	300,249	240,186	204,197	96,075	(60,085)
16	**2023**	305,740	232,255	209,379	96,373	(73,497)
17						
18	**REPAYMENT**					
19	**PERIOD**					
20	**2024**	305,078	236,351	177,551	109,092	(50,292)
21	**2025**	305,078	235,737	189,281	109,717	(63,261)
22	**2026**	305,078	242,077	193,891	110,337	(62,151)
23	**2027**	305,078	244,638	217,909	87,877	(61,148)
24	**2028**	305,078	248,153	223,587	77,068	(52,502)
25	**2029**	305,078	250,088	311,268	2,064	(63,244)
26	**2030**	305,078	251,468	329,773	2,143	(80,447)
27	**2031**	305,078	257,157	358,751	2,197	(103,791)
28	**2032**	305,078	265,463	357,831	2,324	(94,692)
29	**2033**	305,078	268,246	370,252	2,458	(104,464)
30	**2034**	305,078	276,304	269,162	104,064	(96,921)
31	**2035**	305,078	281,531	246,097	127,577	(92,143)
32	**2036**	305,078	293,381	250,731	127,723	(85,073)
33	**2037**	305,078	295,533	308,625	97,293	(110,385)
34	**2038**	305,078	309,282	324,399	97,462	(112,579)
35	**2039**	305,078	313,920	295,834	97,641	(79,556)
36	**2040**	305,078	310,831	298,490	97,802	(85,461)
37	**2041**	305,078	309,396	296,691	105,904	(93,199)
38	**2042**	305,078	313,538	320,916	88,541	(95,919)
39	**2043**	305,078	324,886	313,298	103,733	(92,145)
40	**2044**	305,078	333,873	322,028	102,084	(90,240)
41	**2045**	305,078	347,397	339,898	92,676	(85,176)
42	**2046**	305,078	360,205	329,722	111,171	(80,688)
43	**2047**	305,078	373,346	367,112	83,086	(76,852)
44	**2048**	305,078	387,135	457,899	2,202	(72,966)
45	**2049**	305,078	401,644	466,202	2,325	(66,884)
46	**2050**	305,078	416,909	474,742	2,455	(60,289)
47	**2051**	305,078	432,970	277,692	2,593	152,685
48	**2052**	305,078	449,868	165,724	2,737	281,406
49	**2053**	305,078	461,111	165,724	2,890	292,496
50	**2054**	305,078	463,683	165,724	3,052	294,907
51	**2055**	305,078	463,683	165,724	3,222	294,736
52	**2056**	305,078	463,683	165,724	3,402	294,556
53	**2057**	305,078	463,683	165,724	3,593	294,366
54	**2058**	305,078	463,683	165,724	3,793	294,165
55						
56	**TRANSMISSION**					
57	**TOTALS**	17,697,393	21,127,365	17,612,241	2,853,140	661,983

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 2020	B 2021
1	REVENUES FROM PROPOSED RATES	1,151,269	1,151,547
2			
3	OPERATING EXPENSES		
4	TRANSMISSION OPERATIONS	168,711	171,595
5	TRANSMISSION ENGINEERING	56,570	57,094
6	TRANSMISSION MAINTENANCE	177,560	179,860
7	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	109,597	110,278
8	BPA INTERNAL SUPPORT	103,195	104,681
9	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
10	DEPRECIATION & AMORTIZATION	345,303	349,991
11	TOTAL OPERATING EXPENSES	960,936	973,500
12			
13	INTEREST EXPENSE		
14	INTEREST EXPENSE		
15	FEDERAL APPROPRIATIONS	-	-
16	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
17	ON LONG-TERM DEBT	108,189	115,052
18	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
19	DEBT SERVICE REASSIGNMENT INTEREST	2,960	1,927
20	NON-FEDERAL INTEREST	67,411	65,176
21	PREMIUMS/DISCOUNTS	-	-
22	AFUDC	(15,937)	(16,016)
23	INTEREST INCOME	(2,662)	(2,915)
24	NET INTEREST EXPENSE	141,551	144,815
25			
26	TOTAL EXPENSES	1,102,486	1,118,315
27			
28	NET REVENUES	48,783	33,232

Table 9: Transmission Revised Revenue Test Statement of Cash Flows

($000s)

		A 2020	B 2021
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	48,783	33,232
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	-	-
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	345,303	349,991
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	4,304	3,736
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(27,442)	(26,071)
11	AC INTERTIE CO/FIBER	(3,507)	(3,507)
12	CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION	(7,356)	7,356
13	CASH PROVIDED BY CURRENT OPERATIONS	341,675	346,328
14			
15	CASH USED FOR CAPITAL INVESTMENTS:		
16	INVESTMENT IN:		
17	UTILITY PLANT	(470,870)	(489,393)
18	CASH USED FOR CAPITAL INVESTMENTS	(470,870)	(489,393)
19			
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
21	INCREASE IN LONG-TERM DEBT	430,870	449,393
22	DEBT SERVICE REASSIGNMENT PRINCIPAL	(21,596)	(22,678)
23	REPAYMENT OF CAPITAL LEASES	(74,479)	(73,695)
24	REPAYMENT OF LONG-TERM DEBT	(204,197)	(209,379)
25	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-
26	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	130,598	143,641
27			
28	ANNUAL INCREASE (DECREASE) IN CASH	1,404	576

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)
1	**Thru 2015**	24,961,478	11,059,061	348,748	5,719,577	6,638,882	1,195,210
2							
3	**2016**	1,061,700	579,282	-	244,158	136,358	101,902
4	**2017**	1,091,725	600,846	-	260,927	139,499	90,453
5	**2018**	1,090,198	596,563	-	286,284	140,788	66,563
6	**2019**	1,039,877	597,226	-	305,720	147,600	(10,668)
7	**2020**	1,094,215	612,982	-	339,833	148,893	(7,493)
8							
9	**COST EVALUATION**						
10	**PERIOD**						
11	**2021**	1,103,178	635,733	-	342,090	140,694	(15,340)
12							
13	**RATE APPROVAL**						
14	**PERIOD**						
15	**2022**	1,151,269	615,633	-	345,303	141,551	48,783
16	**2023**	1,151,547	623,509	-	349,991	144,815	33,232
17							
18	**REPAYMENT**						
19	**PERIOD**						
20	**2024**	1,151,547	623,509	(6,897)	349,991	148,442	36,503
21	**2025**	1,151,547	623,509	(6,897)	349,991	157,104	27,840
22	**2026**	1,151,547	623,509	(6,897)	349,991	189,381	(4,437)
23	**2027**	1,151,547	623,509	(6,897)	349,991	194,030	(9,085)
24	**2028**	1,151,547	623,509	(6,897)	349,991	191,217	(6,273)
25	**2029**	1,151,547	623,509	(6,897)	349,991	190,813	(5,868)
26	**2030**	1,151,547	623,509	(6,897)	349,991	192,063	(7,118)
27	**2031**	1,151,547	623,509	(6,897)	349,991	177,668	7,277
28	**2032**	1,151,547	623,509	(6,897)	349,991	169,192	15,753
29	**2033**	1,151,547	623,509	(6,897)	349,991	168,320	16,624
30	**2034**	1,151,547	623,509	(6,897)	349,991	163,580	21,365
31	**2035**	1,151,547	623,509	(6,897)	349,991	161,808	23,137
32	**2036**	1,151,547	623,509	(6,897)	349,991	162,049	22,895
33	**2037**	1,151,547	623,509	(6,897)	349,991	164,755	20,190
34	**2038**	1,151,547	623,509	(6,897)	349,991	164,777	20,167
35	**2039**	1,151,547	623,509	(6,897)	349,991	164,526	20,418
36	**2040**	1,151,547	623,509	(6,897)	349,991	163,036	21,909
37	**2041**	1,151,547	623,509	(6,897)	349,991	164,766	20,178
38	**2042**	1,151,547	623,509	(6,897)	349,991	166,534	18,410
39	**2043**	1,151,547	623,509	(6,897)	349,991	169,082	15,863
40	**2044**	1,151,547	623,509	(6,897)	349,991	170,629	14,316
41	**2045**	1,151,547	623,509	(6,897)	349,991	169,495	15,449
42	**2046**	1,151,547	623,509	(6,897)	349,991	166,614	18,331
43	**2047**	1,151,547	623,509	(6,897)	349,991	163,723	21,222
44	**2048**	1,151,547	623,509	(6,897)	349,991	161,386	23,559
45	**2049**	1,151,547	623,509	(6,897)	349,991	157,813	27,132
46	**2050**	1,151,547	623,509	(6,897)	349,991	152,701	32,243
47	**2051**	1,151,547	623,509	(6,897)	349,991	149,205	35,739
48	**2052**	1,151,547	623,509	(6,897)	349,991	145,562	39,383
49	**2053**	1,151,547	623,509	(6,897)	349,991	141,765	43,179
50	**2054**	1,151,547	623,509	(6,897)	349,991	137,809	47,135
51	**2055**	1,151,547	623,509	(6,897)	349,991	133,687	51,257
52	**2056**	1,151,547	623,509	(6,897)	349,991	129,391	55,553
53	**2057**	1,151,547	623,509	(6,897)	349,991	124,915	60,029
54	**2058**	1,151,547	623,509	(6,897)	349,991	120,251	64,694
55							
56	**TRANSMISSION**						
57	**TOTALS**	71,970,573	35,720,581	456,086	19,813,703	13,934,200	2,046,001

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 2015**	5,284,623	7,472,648	6,435,803	586,532	450,314
3	**2016**	231,397	548,299	383,410	186,696	(21,807)
4	**2017**	248,168	317,521	96,439	201,768	19,314
5	**2018**	272,676	316,185	47,906	193,402	74,877
6	**2019**	6,461	(4,207)	235,016	17,304	(256,526)
7	**2020**	297,230	289,737	199,900	98,999	(9,162)
	COST EVALUATION PERIOD					
11	**2021**	322,014	280,232	284,700	99,863	(104,331)
	RATE APPROVAL PERIOD					
15	**2022**	292,893	301,675	204,197	96,075	1,404
16	**2023**	313,096	306,328	209,379	96,373	576
	REPAYMENT PERIOD					
20	**2024**	444,955	481,458	177,551	109,092	194,814
21	**2025**	444,955	472,796	189,281	109,717	173,797
22	**2026**	444,955	440,519	193,891	110,337	136,291
23	**2027**	444,955	435,870	217,909	87,877	130,084
24	**2028**	444,955	438,683	223,587	77,068	138,028
25	**2029**	444,955	439,087	311,268	2,064	125,756
26	**2030**	444,955	437,837	329,773	2,143	105,922
27	**2031**	444,955	452,232	358,751	2,197	91,284
28	**2032**	444,955	460,708	357,831	2,324	100,553
29	**2033**	444,955	461,580	370,252	2,458	88,870
30	**2034**	444,955	466,320	269,162	104,064	93,095
31	**2035**	444,955	468,092	246,097	127,577	94,419
32	**2036**	444,955	467,851	250,731	127,723	89,397
33	**2037**	444,955	465,145	308,625	97,293	59,227
34	**2038**	444,955	465,123	324,399	97,462	43,261
35	**2039**	444,955	465,373	295,834	97,641	71,898
36	**2040**	444,955	466,864	298,490	97,802	70,573
37	**2041**	444,955	465,134	296,691	105,904	62,539
38	**2042**	444,955	463,366	320,916	88,541	53,909
39	**2043**	444,955	460,818	313,298	103,733	43,787
40	**2044**	444,955	459,271	322,028	102,084	35,158
41	**2045**	444,955	460,405	339,898	92,676	27,831
42	**2046**	444,955	463,286	329,722	111,171	22,393
43	**2047**	444,955	466,177	367,112	83,086	15,979
44	**2048**	444,955	468,514	457,899	2,202	8,413
45	**2049**	444,955	472,087	466,202	2,325	3,559
46	**2050**	444,955	477,198	474,742	2,455	1
47	**2051**	444,955	480,695	277,692	2,593	200,410
48	**2052**	444,955	484,338	165,724	2,737	315,877
49	**2053**	444,955	488,135	165,724	2,890	319,520
50	**2054**	444,955	492,091	165,724	3,052	323,315
51	**2055**	444,955	496,213	165,724	3,222	327,266
52	**2056**	444,955	500,509	165,724	3,402	331,382
53	**2057**	444,955	504,985	165,724	3,593	335,668
54	**2058**	444,955	509,649	165,724	3,793	340,132
	TRANSMISSION					
57	**TOTALS**	22,593,113	25,525,487	17,612,241	2,853,140	5,060,106

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	2021	14,736,798	-	14,736,798	161,900	-	3,683,740	7,067,783
2	2022	430,869	-	15,167,667	204,197	-	3,910,412	7,294,455
3	2023	514,052	-	15,681,720	209,379	-	4,215,086	7,599,129
4	2024	-	165,724	15,847,444	68,800	108,751	4,203,259	7,696,053
5	2025	-	165,724	16,013,168	114,000	75,281	4,179,702	7,747,777
6	2026	-	165,724	16,178,892	125,000	68,891	4,151,535	7,788,501
7	2027	-	165,724	16,344,616	130,870	87,039	4,099,349	7,823,355
8	2028	-	165,724	16,510,340	45,766	177,821	4,041,486	7,724,513
9	2029	-	165,724	16,676,064	85,793	225,476	3,895,942	7,804,444
10	2030	-	165,724	16,841,788	73,000	256,773	3,731,893	7,897,168
11	2031	-	165,724	17,007,512	56,668	302,083	3,538,866	7,986,892
12	2032	-	165,724	17,173,236	-	357,831	3,346,759	8,053,716
13	2033	-	165,724	17,338,960	59,000	311,252	3,142,232	8,120,440
14	2034	-	165,724	17,504,684	82,300	186,862	3,038,794	8,120,864
15	2035	-	165,724	17,670,408	29,091	217,006	2,958,421	8,110,497
16	2036	-	165,724	17,836,132	29,000	221,731	2,873,414	8,022,221
17	2037	-	165,724	18,001,856	1,453	307,173	2,730,513	8,073,552
18	2038	-	165,724	18,167,580	-	324,399	2,571,838	8,133,480
19	2039	-	165,724	18,333,304	43,978	251,857	2,441,727	8,140,204
20	2040	-	165,724	18,499,028	-	298,490	2,308,961	8,250,928
21	2041	-	165,724	18,664,752	-	296,691	2,177,994	8,361,652
22	2042	-	165,724	18,830,476	-	320,916	2,022,802	8,467,376
23	2043	-	165,724	18,996,200	-	313,298	1,875,228	8,571,100
24	2044	-	165,724	19,161,924	-	322,028	1,718,923	8,658,126
25	2045	-	165,724	19,327,648	-	339,898	1,544,750	8,612,517
26	2046	-	165,724	19,493,372	-	329,722	1,380,751	8,521,907
27	2047	-	165,724	19,659,096	-	367,112	1,179,363	8,482,295
28	2048	-	165,724	19,824,820	-	457,899	887,189	8,328,595
29	2049		165,724	19,990,544	-	466,202	586,710	8,246,095
30	2050	-	165,724	20,156,268	-	474,742	277,692	8,277,395
31	2051	-	165,724	20,321,992	-	277,692	165,724	8,303,518
32	2052	-	165,724	20,487,716	-	165,724	165,724	8,329,640
33	2053	-	165,724	20,653,440	-	165,724	165,724	8,355,763
34	2054	-	165,724	20,819,164	-	165,724	165,724	8,521,487
35	2055	-	165,724	20,984,888	-	165,724	165,724	8,687,211
36	2056	-	165,724	21,150,612	-	165,724	165,724	8,852,935
37	2057	-	165,724	21,316,336	-	165,724	165,724	9,018,659
38	2058	-	165,724	21,482,060	-	165,724	165,724	9,184,383
39		**$15,681,720**	**$5,800,340**		**$1,520,195**	**$8,904,983**		

BONNEVILLE POWER ADMINISTRATION
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