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-18 Rate Proceeding

Final Proposal

Transmission Revenue Requirement Study

BP-18-FS-BPA-09

July 2017

TRANSMISSION REVENUE REQUIREMENT STUDY

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COMMONLY USED ACRONYMS AND SHORT FORMS

AC	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
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Bps	basis points
Btu	British thermal unit
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
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
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
EIM	Energy imbalance market

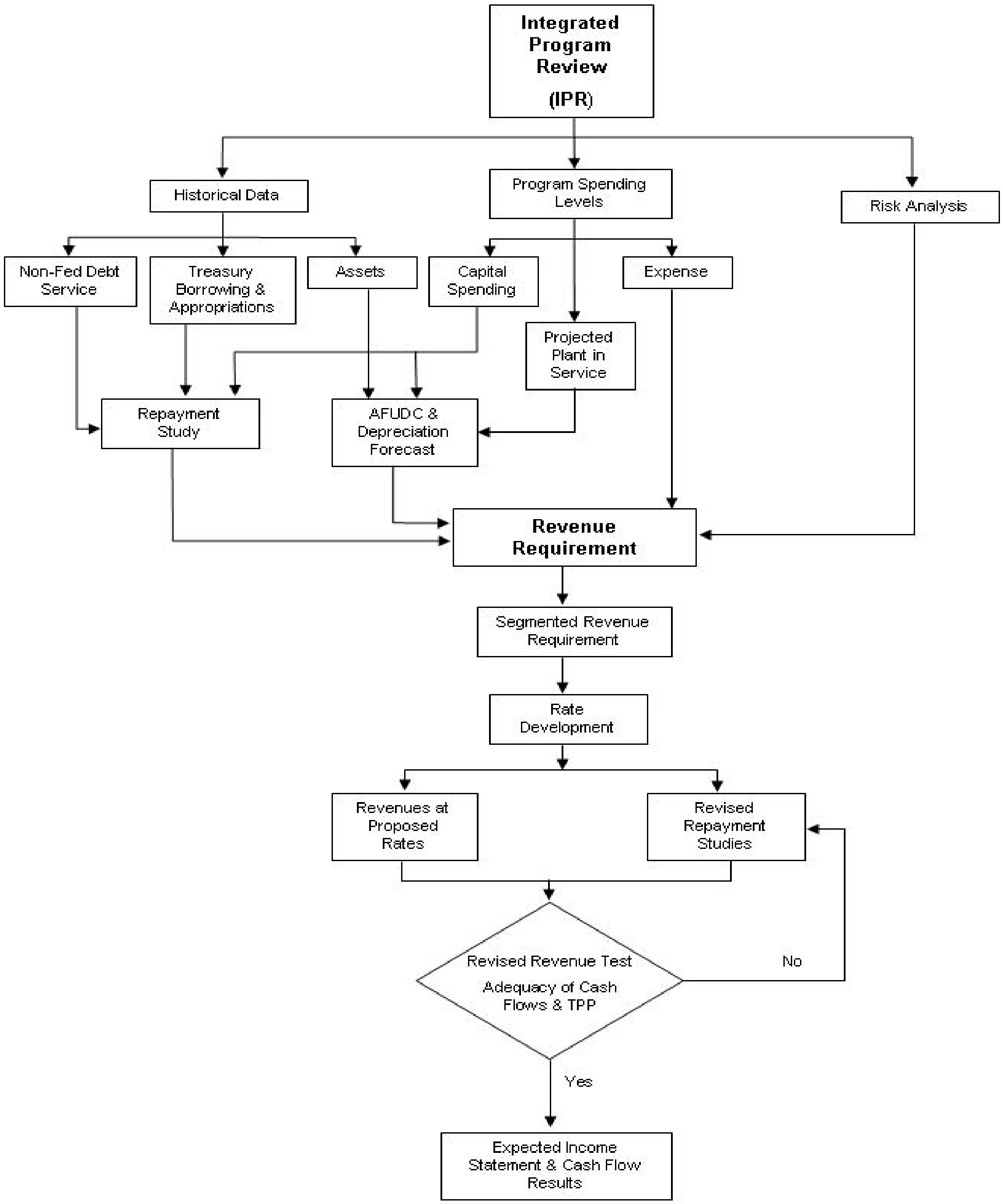
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FOIA	Freedom Of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
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
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
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
LTF	Long-term Form
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	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability (assessment/charge)
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
Project Act	Bonneville Project Act
PS	Power Services
PSC	power sales contract

PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
RDC	Reserves Distribution Clause
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
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
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
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service

VERBS	Variable Energy Resources 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

Figure 1: Transmission Revenue Requirement Process



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 (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 initial proposal filing includes Fiscal Year (FY) 2017 and the proposed rate period, FY 2018–2019. 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-18-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-18-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-18-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, above. Once the revenue requirement is completed, it is segmented and passed to the rate development process, where it is used to develop rates in the Transmission Rates Study and Documentation, BP-18-FS-BPA-08.

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 be adequate to recover the transmission revenue requirement for the rate period (although other reasons may exist for revising rates).

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-18-FS-BPA-05, § 5.2.3.2.

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed transmission rates for FY 2018–2019. 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 2018–19 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 2018–2019.

1.2.2.2 Repayment Schedules

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

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

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

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

> results in a uniform cost per unit of power sold, and permits the maintenance of stable rates for extended periods. It also facilitates the orderly marketing of power and permits Bonneville Power Administration customers, which include both electric utilities and electroprocess industries, to plan for the future with assurance.

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

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

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

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

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

BPA and the other Federal power marketing agencies were transferred to the newly established Department of Energy on October 1, 1977. Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq*. 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 45 years) or within a maximum of 50 years, whichever is less;

- 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.

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2. DEVELOPMENT OF REVENUE REQUIREMENT

2.1 Spending Level Development

The development of program spending levels occurs outside the rate process. For the FY 2018–2019 rate period it began in June of 2016, when BPA hosted the 2016 Integrated Program Review (IPR) and Capital Investment Review (CIR). 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 2016 IPR and CIR discussion with the release of the IPR and CIR 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 2017–2019 (the cost evaluation period). The opening workshop launched an eight-week 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 and CIR 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.

After considering the comments received, BPA released a final IPR and CIR close-out report in October 2016.

After this rate proceeding began, BPA initiated an IPR 2 process for a review of a small number of programs and activities: expense and capital spending by the U.S. Army Corps of Engineers and Bureau of Reclamation, operations and maintenance costs at the Columbia Generation Station, the Commercial Operations Key Strategic Initiative, and workforce spending. Workshops were held in February 2017. A final report detailing reductions in spending forecasts was released in April 2017.

This study incorporates the spending levels identified in the 2016 IPR and CIR final close-out report as well as the final report of the IPR 2, which can be found on BPA's public website: https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2016.aspx

2.2 Capital Investments

The forecast of BPA's capital investments for FY 2018–2019 used in developing the BP-18 transmission final proposal rates was produced from the CIR levels in the IPR/CIR close-out reports. The following section describes the capital investment forecasts.

BPA transmission capital outlay projections including allowance for funds used during construction (AFUDC) for the FY 2018–2019 rate period are $1,027 million, excluding the effect of reserve financing, which reduces the borrowing amount. Rounded, these investments are:

- transmission programs ($991 million)
- environmental program ($15 million)
- corporate capital program ($22 million)

Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, Ch. 7.

2.2.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be one of the primary sources of capital used to finance projected FY 2018–2019 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

This study includes the outstanding balances of the original capital investments in the Federal transmission system that was financed by Congressional appropriations. After the full implementation of BPA's self-funding authority under the Transmission System Act, transmission investments were no longer funded by annual appropriations. The Refinancing Act reset the unpaid principal of all outstanding BPA appropriations and assigned current market interest rates to the principal. New principal amounts were established at the beginning of FY 1997 at the present value of the principal and annual interest payments BPA would make to the Treasury for these obligations in the absence of the Refinancing Act, plus $100 million. Before implementation of the Refinancing Act, $1,461.9 million in BPA appropriations was outstanding. After implementation of the Refinancing Act, $1,075.4 million in BPA appropriations was outstanding. The Refinancing Act restricted prepayment of the new principal to $100 million in FY 1997–2001. Other repayment terms were unaffected. Through annual repayments, outstanding appropriations for transmission investments had been reduced to $119 million as of September 30, 2016 after the annual treasury payment had been made.

2.2.3 Use of Financial Reserves for Capital Investment

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

2.2.4 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 a transaction in 2004 with the Northwest Infrastructure Financing Corporation (NIFC), a subsidiary of JH Management, to provide for the construction of the 500-kV Schultz-Wautoma transmission line (Schultz-Wautoma line). NIFC issued bonds to finance the construction. BPA is making semiannual lease payments to NIFC through 2034, concluding with a single payment for the principal due on the bonds.

Payment of the debt incurred by NIFC to construct the line is secured solely by BPA's revenues. During the term of the lease, BPA will operate the Schultz-Wautoma line and provide transmission and ancillary services over the facilities. Since the completion of the Schultz-Wautoma project, BPA has entered into additional lease financing arrangements with NIFC, Port of Morrow, and Idaho Energy Resources Authority. BPA will continue to utilize the lease purchase program for transmission construction. The revenue requirement includes all transactions BPA expects to complete by the date of the Final Proposal.

The revenue requirement also includes projected lease purchase agreements. Half of the projected transmission investments, totaling $481 million over the rate period, are assumed to be financed through the lease purchase program. *See* Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, § 8.2. Like Treasury bonds, lease purchase obligations are given a maximium maturity of 30 years. They are modeled in a manner consistent with actual practice. Projected lease purchase obligations are modeled with an interest rate of the current 3-month LIBOR forecast plus 60 basis points for the first 7 years, and taxable non-Federal interest rates for up to the 23 remaining years. The principal has an additional one percent added to account for the cost of issuance.

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 two types of capital construction projects. The first form of customer financing occurs under generation interconnection agreements (LGIA or SGIA). BPA amended its Open

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

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

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

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

For the forecasts of interest expense and transmission credits associated with generator interconnection agreements and with the COI upgrade at current and proposed rates, see Transmission Rates Study and Documentation, BP-18-FS-BPA-08, Tables 16.1 and 16.2.

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-16-E-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-18-FS-BPA-07.

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3. TRANSMISSION REVENUE REQUIREMENTS

3.1 Revenue Requirement Format

For each year of a rate period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of total expenses, any 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 20), MRNR (line 22), and PNRR (line 23). The sum of these four major components is the total revenue requirement (line 25) for each year of the rate period.

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

3.2 Current Revenue Test

Consistent with DOE Order RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test, exhibited in Tables 5 and 6, determines whether the revenue expected from current rates will meet cost recovery requirements during the FY 2018–2019 rate period and the ensuing repayment period. For revenue at current rates, see Transmission Rates Study and Documentation, BP-18-FS-BPA-08, Table 12.

The result of the current revenue test demonstrates that projected revenue from current rates is adequate to meet the cost recovery criteria of Order RA 6120.2 over the repayment period, because the net position is positive. *See* Table 7, column K. This means that current rates could be extended (although other reasons may exist for revising rates).

3.3 Revised Revenue Test

Consistent with DOE Order RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenue projected from proposed rates will meet cost recovery requirements for the rate period. The revised revenue test is conducted using the forecast of revenue under proposed rates. Transmission Rates Study and Documentation, BP-18-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 2018–2019. 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
		FY 2018	FY 2019	Rate Period Average
1	PROJECTED REVENUES FROM PROPOSED RATES	1,045,388	1,052,820	1,049,104
2	PROJECTED EXPENSES	1,027,204	1,051,440	1,039,322
3	NET REVENUES	18,184	1,380	9,782

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

		A	B	C
		BOND AMORTIZATION	APPROPRIATIONS AMORTIZATION	TOTAL
1	2018	45,950	1,956	47,906
2	2019	213,963	21,053	235,016
3	TOTAL	259,913	23,008	282,922

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

		A FY 2018	B FY 2019
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	167,050	168,007
3	TRANSMISSION ENGINEERING	56,351	57,718
4	TRANSMISSION MAINTENANCE	176,580	178,125
5	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	119,460	111,983
6	BPA INTERNAL SUPPORT	93,940	95,607
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	(7,548)	(8,539)
8	DEPRECIATION & AMORTIZATION	273,164	284,422
9	TOTAL OPERATING EXPENSES	878,997	887,323
10	INTEREST EXPENSE		
11	INTEREST EXPENSE		
12	FEDERAL APPROPRIATIONS	1,659	1,518
13	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
14	ON LONG-TERM DEBT	100,999	106,597
15	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
16	DEBT SERVICE REASSIGNMENT INTEREST	13,964	5,111
17	NON-FEDERAL INTEREST	77,156	97,552
18	PREMIUMS/DISCOUNTS	-	556
18	AFUDC	(24,733)	(24,819)
19	INTEREST INCOME	(2,412)	(3,941)
20	NET INTEREST EXPENSE	148,225	164,167
21	TOTAL EXPENSES	1,027,222	1,051,490
22	MINIMUM REQUIRED NET REVENUE 1/	8,626	348
23	PLANNED NET REVENUES FOR RISK	-	-
24	TOTAL PLANNED NET REVENUE	8,626	348
25	TOTAL REVENUE REQUIREMENT	1,035,849	1,051,837

1/ See note on cash flow table

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

		A FY 2018	B FY 2019
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUE	8,626	348
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	273,164	284,422
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	4,325	4,111
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(17,256)	(14,767)
11	AC INTERTIE CO/FIBER	(9,168)	(3,387)
12	CASH PROVIDED BY CURRENT OPERATIONS	256,283	267,319
13	CASH USED FOR CAPITAL INVESTMENTS:		
14	INVESTMENT IN:		
15	UTILITY PLANT	(505,808)	(521,577)
16	CASH USED FOR CAPITAL INVESTMENTS	(505,808)	(521,577)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
18	INCREASE IN LONG-TERM DEBT	490,808	506,577
19	DEBT SERVICE REASSIGNMENT PRINCIPAL	(191,504)	(4,838)
20	REPAYMENT OF CAPITAL LEASES	(1,874)	(12,466)
21	REPAYMENT OF LONG-TERM DEBT	(45,950)	(213,963)
22	REPAYMENT OF CAPITAL APPROPRIATIONS	(1,956)	(21,053)
23	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	249,525	254,258
24	ANNUAL INCREASE (DECREASE) IN CASH [1/]	-	-
25	PLANNED NET REVENUE FOR RISK	-	-
26	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	-	-

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

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

		A FY 2018	B FY 2019
1	REVENUES FROM CURRENT RATES	1,059,062	1,067,126
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	167,050	168,007
4	TRANSMISSION ENGINEERING	56,351	57,718
5	TRANSMISSION MAINTENANCE	176,580	178,125
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	119,460	111,983
7	BPA INTERNAL SUPPORT	93,940	95,607
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(7,548)	(8,539)
9	DEPRECIATION & AMORTIZATION	273,164	284,422
10	TOTAL OPERATING EXPENSES	878,997	887,323
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	1,659	1,518
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	100,999	106,597
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
17	DEBT SERVICE REASSIGNMENT INTEREST	13,964	5,111
18	NON-FEDERAL INTEREST	77,156	97,552
17	PREMIUMS/DISCOUNTS	-	556
19	AFUDC	(24,733)	(24,819)
20	INTEREST INCOME	(2,461)	(4,129)
21	NET INTEREST EXPENSE	148,177	163,979
22	TOTAL EXPENSES	1,027,174	1,051,302
23	NET REVENUES	31,888	15,825

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

		A FY 2018	B FY 2019
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	31,888	15,825
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	273,164	284,422
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	4,325	4,111
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(17,256)	(14,767)
11	AC INTERTIE CO/FIBER	(9,168)	(3,387)
12	CASH PROVIDED BY CURRENT OPERATIONS	279,545	282,796
13	CASH USED FOR CAPITAL INVESTMENTS:		
14	INVESTMENT IN:		
15	UTILITY PLANT	(505,808)	(521,577)
16	CASH USED FOR CAPITAL INVESTMENTS	(505,808)	(521,577)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
18	INCREASE IN LONG-TERM DEBT	490,808	506,577
19	DEBT SERVICE REASSIGNMENT PRINCIPAL	(191,504)	(4,838)
20	REPAYMENT OF CAPITAL LEASES	(1,874)	(12,466)
21	REPAYMENT OF LONG-TERM DEBT	(45,950)	(213,963)
22	REPAYMENT OF CAPITAL APPROPRIATIONS	(1,956)	(21,053)
23	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	249,525	254,258
24	ANNUAL INCREASE (DECREASE) IN CASH	23,262	15,477

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

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

($000s)

		A	B	C	D	E	F	G	H	I	J	K
	YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	DEBT SERVICE OFFSETS (REV REQ STUDY DOC)	DEPRECIATION	NET INTEREST (TABLE D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION 2/ (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	NET POSITION (K=H-I-J)
	COMBINED CUMULATIVE											
1	**1977**	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
2	**1978-2016**	22,724,227	10,659,129	0	5,156,689	5,555,070	1,353,341	4,708,973	7,270,129	6,190,753	773,227	306,148
	COST EVALUATION PERIOD											
3	**2017**	1,082,156	604,801		259,548	143,160	74,646	246,516	256,162	96,439	201,768	(42,046)
	RATE APPROVAL PERIOD											
4	**2018**	1,059,062	605,833	0	273,164	148,177	31,888	232,657	264,545	47,906	193,377	23,262
5	**2019**	1,067,126	602,901	0	284,422	163,979	15,824	251,972	267,796	235,016	17,304	15,477
	REPAYMENT PERIOD											
6	**2020**	1,067,126	602,901	(7,829)	284,422	180,506	7,127	251,972	259,099	143,773	98,925	16,401
7	**2021**	1,067,126	602,901	(8,071)	284,422	180,682	7,193	251,972	259,165	142,268	100,084	16,812
8	**2022**	1,067,126	602,901	(8,273)	284,422	181,561	6,516	251,972	258,488	146,430	94,986	17,072
9	**2023**	1,067,126	602,901	(8,419)	284,422	182,970	5,253	251,972	257,225	140,747	99,237	17,241
10	**2024**	1,067,126	602,901	(8,579)	284,422	182,817	5,565	251,972	257,537	139,130	100,936	17,471
11	**2025**	1,067,126	602,901	(8,743)	284,422	187,591	956	251,972	252,928	133,745	101,328	17,855
12	**2026**	1,067,126	602,901	(8,940)	284,422	188,061	683	251,972	252,655	134,746	99,507	18,402
13	**2027**	1,067,126	602,901	(9,079)	284,422	189,860	(977)	251,972	250,995	129,873	102,308	18,814
14	**2028**	1,067,126	602,901	(9,254)	284,422	198,678	(9,620)	251,972	242,352	130,807	92,732	18,813
15	**2029**	1,067,126	602,901	(9,398)	284,422	194,301	(5,099)	251,972	246,873	134,510	93,982	18,381
16	**2030**	1,067,126	602,901	(9,653)	284,422	193,217	(3,761)	251,972	248,211	130,564	99,306	18,341
17	**2031**	1,067,126	602,901	(9,860)	284,422	192,509	(2,846)	251,972	249,126	131,294	99,491	18,341
18	**2032**	1,067,126	602,901	(10,049)	284,422	193,751	(3,898)	251,972	248,074	128,361	101,372	18,341
19	**2033**	1,067,126	602,901	(10,243)	284,422	195,819	(5,773)	251,972	246,199	114,404	113,453	18,341
20	**2034**	1,067,126	602,901	(10,494)	284,422	193,872	(3,574)	251,972	248,398	125,054	105,003	18,341
21	**2035**	1,067,126	602,901	(10,682)	284,422	199,994	(9,508)	251,972	242,463	95,663	128,459	18,341
22	**2036**	1,067,126	602,901	(10,859)	284,422	203,824	(13,162)	251,972	238,810	91,921	128,548	18,341
23	**2037**	1,067,126	602,901	(11,028)	284,422	209,396	(18,564)	251,972	233,408	110,898	104,169	18,341
24	**2038**	1,067,126	602,901	(11,183)	284,422	212,767	(21,780)	251,972	230,192	107,635	104,216	18,341
25	**2039**	1,067,126	602,901	(11,357)	284,422	215,518	(24,357)	251,972	227,614	104,311	104,962	18,341
26	**2040**	1,067,126	602,901	(11,516)	284,422	216,337	(25,017)	251,972	226,955	84,763	123,850	18,341
27	**2041**	1,067,126	602,901	(11,662)	284,422	223,916	(32,450)	251,972	219,522	112,097	89,083	18,341
28	**2042**	1,067,126	602,901	(11,796)	284,422	230,865	(39,266)	251,972	212,706	70,604	123,761	18,341
29	**2043**	1,067,126	602,901	(11,985)	284,422	236,990	(45,201)	251,972	206,770	67,007	121,422	18,341
30	**2044**	1,067,126	602,901	(12,145)	284,422	244,404	(52,456)	251,972	199,516	61,495	119,680	18,341
31	**2045**	1,067,126	602,901	(12,231)	284,422	251,039	(59,004)	251,972	192,968	50,000	123,319	19,649
32	**2046**	1,067,126	602,901	(12,367)	284,422	258,092	(65,921)	251,972	186,051	43,083	123,319	19,649
33	**2047**	1,067,126	602,901	(12,517)	284,422	264,488	(72,167)	251,972	179,804	160,155	-	19,649
34	**2048**	1,067,126	602,901	(12,688)	284,422	272,532	(80,040)	251,972	171,932	152,283	-	19,649
35	**2049**	1,067,126	602,901	(12,803)	284,422	277,339	(84,732)	251,972	167,240	147,591	-	19,649
36	**2050**	1,067,126	602,901	(12,897)	284,422	284,695	(91,994)	251,972	159,977	140,328	-	19,649
37	**2051**	1,067,126	602,901	(12,979)	284,422	292,478	(99,695)	251,972	152,277	132,628	-	19,649
38	**2052**	1,067,126	602,901	(13,131)	284,422	300,736	(107,801)	251,972	144,171	124,521	-	19,649
39	**2053**	1,067,126	602,901	(13,258)	284,422	309,515	(116,453)	251,972	135,519	115,870	-	19,649
40	**2054**	1,067,126	602,901	(13,394)	284,422	318,830	(125,633)	251,972	126,339	106,690	-	19,649
	TRANSMISSION											
41	**TOTALS**	66,580,943	34,538,026	(30,617)	16,735,638	15,090,506	247,391	15,066,174	16,456,380	11,283,822	4,083,112	1,089,447

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.
2/INCLUDES ADJUSTMENTS FOR NON-CASH REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.

Table 8: Transmission Revised Revenue Test Income Statement

($000s)

		A FY 2018	B FY 2019
1	REVENUES FROM PROPOSED RATES	1,045,388	1,052,820
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	167,050	168,007
4	TRANSMISSION ENGINEERING	56,351	57,718
5	TRANSMISSION MAINTENANCE	176,580	178,125
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	119,460	111,983
7	BPA INTERNAL SUPPORT	93,940	95,607
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(7,548)	(8,539)
9	DEPRECIATION & AMORTIZATION	273,164	284,422
10	TOTAL OPERATING EXPENSES	878,997	887,323
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	1,659	1,518
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	100,999	106,597
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
17	DEBT SERVICE REASSIGNMENT INTEREST	13,964	5,111
18	NON-FEDERAL INTEREST	77,156	97,552
19	PREMIUMS/DISCOUNTS	-	556
19	AFUDC	(24,733)	(24,819)
20	INTEREST INCOME	(2,430)	(3,991)
21	NET INTEREST EXPENSE	148,208	164,117
22	TOTAL EXPENSES	1,027,204	1,051,440
23	NET REVENUES	18,184	1,380

Table 9: Transmission Revised Revenue Test Statement of Cash Flows

($000s)

		A FY 2018	B FY 2019
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	18,184	1,380
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	273,164	284,422
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	4,325	4,111
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(17,256)	(14,767)
11	AC INTERTIE CO/FIBER	(9,168)	(3,387)
12	CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION		
13	CASH PROVIDED BY CURRENT OPERATIONS	265,840	268,352
14	CASH USED FOR CAPITAL INVESTMENTS:		
15	INVESTMENT IN:		
16	UTILITY PLANT	(505,808)	(521,577)
17	CASH USED FOR CAPITAL INVESTMENTS	(505,808)	(521,577)
18	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
19	INCREASE IN LONG-TERM DEBT	490,808	506,577
20	DEBT SERVICE REASSIGNMENT PRINCIPAL	(191,504)	(4,838)
21	REPAYMENT OF CAPITAL LEASES	(1,874)	(12,466)
22	REPAYMENT OF LONG-TERM DEBT	(45,950)	(213,963)
23	REPAYMENT OF CAPITAL APPROPRIATIONS	(1,956)	(21,053)
24	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	249,525	254,258
25	ANNUAL INCREASE (DECREASE) IN CASH	9,557	1,033

1/ Line 25 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

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

($000s)

		A	B	C	D	E	F	G	H	I	J	K
	YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	DEBT SERVICE OFFSETS (REV REQ STUDY DOC)	DEPRECIATION	NET INTEREST (TABLE D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION 2/ (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	NET POSITION (K=H-I-J)
	COMBINED CUMULATIVE											
1	**1977**	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
2	**1978-2016**	22,724,227	10,659,129	0	5,156,689	5,555,070	1,353,341	4,708,973	7,270,129	6,190,753	773,227	306,148
	COST EVALUATION PERIOD											
3	**2017**	1,082,156	604,801	0	259,548	143,160	74,646	246,516	256,162	96,439	201,768	(42,046)
	RATE APPROVAL PERIOD											
4	**2018**	1,045,388	605,833	0	273,164	148,208	18,184	232,657	250,840	47,906	193,377	9,557
5	**2019**	1,052,820	602,901	0	284,422	164,117	1,380	251,972	253,352	235,016	17,304	1,033
	REPAYMENT PERIOD											
6	**2020**	1,052,820	602,901	(7,829)	284,422	180,644	(7,318)	251,972	244,654	143,773	98,925	1,956
7	**2021**	1,052,820	602,901	(8,071)	284,422	180,820	(7,252)	251,972	244,720	142,268	100,084	2,368
8	**2022**	1,052,820	602,901	(8,273)	284,422	181,699	(7,929)	251,972	244,043	146,430	94,986	2,628
9	**2023**	1,052,820	602,901	(8,419)	284,422	183,108	(9,191)	251,972	242,780	140,747	99,237	2,796
10	**2024**	1,052,820	602,901	(8,579)	284,422	182,955	(8,879)	251,972	243,093	139,130	100,936	3,027
11	**2025**	1,052,820	602,901	(8,743)	284,422	187,729	(13,488)	251,972	238,483	133,745	101,328	3,411
12	**2026**	1,052,820	602,901	(8,940)	284,422	188,199	(13,762)	251,972	238,210	134,746	99,507	3,957
13	**2027**	1,052,820	602,901	(9,079)	284,422	189,998	(15,422)	251,972	236,550	129,873	102,308	4,369
14	**2028**	1,052,820	602,901	(9,254)	284,422	198,816	(24,065)	251,972	227,907	130,807	92,732	4,369
15	**2029**	1,052,820	602,901	(9,398)	284,422	194,439	(19,543)	251,972	232,428	134,510	93,982	3,937
16	**2030**	1,052,820	602,901	(9,653)	284,422	193,355	(18,205)	251,972	233,766	130,564	99,306	3,897
17	**2031**	1,052,820	602,901	(9,860)	284,422	192,647	(17,290)	251,972	234,681	131,294	99,491	3,897
18	**2032**	1,052,820	602,901	(10,049)	284,422	193,889	(18,343)	251,972	233,629	128,361	101,372	3,897
19	**2033**	1,052,820	602,901	(10,243)	284,422	195,958	(20,218)	251,972	231,754	114,404	113,453	3,897
20	**2034**	1,052,820	602,901	(10,494)	284,422	194,010	(18,018)	251,972	233,954	125,054	105,003	3,897
21	**2035**	1,052,820	602,901	(10,682)	284,422	200,132	(23,953)	251,972	228,019	95,663	128,459	3,897
22	**2036**	1,052,820	602,901	(10,859)	284,422	203,962	(27,607)	251,972	224,365	91,921	128,548	3,897
23	**2037**	1,052,820	602,901	(11,028)	284,422	209,534	(33,008)	251,972	218,963	110,898	104,169	3,897
24	**2038**	1,052,820	602,901	(11,183)	284,422	212,905	(36,225)	251,972	215,747	107,635	104,216	3,897
25	**2039**	1,052,820	602,901	(11,357)	284,422	215,656	(38,802)	251,972	213,170	104,311	104,962	3,897
26	**2040**	1,052,820	602,901	(11,516)	284,422	216,475	(39,462)	251,972	212,510	84,763	123,850	3,897
27	**2041**	1,052,820	602,901	(11,662)	284,422	224,054	(46,895)	251,972	205,077	112,097	89,083	3,897
28	**2042**	1,052,820	602,901	(11,796)	284,422	231,003	(53,710)	251,972	198,261	70,604	123,761	3,897
29	**2043**	1,052,820	602,901	(11,985)	284,422	237,128	(59,646)	251,972	192,326	67,007	121,422	3,896
30	**2044**	1,052,820	602,901	(12,145)	284,422	244,542	(66,900)	251,972	185,072	61,495	119,680	3,897
31	**2045**	1,052,820	602,901	(12,231)	284,422	251,177	(73,449)	251,972	178,523	50,000	123,319	5,205
32	**2046**	1,052,820	602,901	(12,367)	284,422	258,230	(80,365)	251,972	171,606	43,083	123,319	5,205
33	**2047**	1,052,820	602,901	(12,517)	284,422	264,626	(86,612)	251,972	165,360	160,155	-	5,205
34	**2048**	1,052,820	602,901	(12,688)	284,422	272,670	(94,484)	251,972	157,487	152,283	-	5,205
35	**2049**	1,052,820	602,901	(12,803)	284,422	277,477	(99,177)	251,972	152,795	147,591	-	5,205
36	**2050**	1,052,820	602,901	(12,897)	284,422	284,833	(106,439)	251,972	145,533	140,328	-	5,205
37	**2051**	1,052,820	602,901	(12,979)	284,422	292,616	(114,139)	251,972	137,832	132,628	-	5,205
38	**2052**	1,052,820	602,901	(13,131)	284,422	300,874	(122,246)	251,972	129,726	124,521	-	5,205
39	**2053**	1,052,820	602,901	(13,258)	284,422	309,653	(130,898)	251,972	121,074	115,870	-	5,205
40	**2054**	1,052,820	602,901	(13,394)	284,422	318,968	(140,077)	251,972	111,895	106,690	-	5,205
41	**TRANSMISSION TOTALS**	66,052,237	34,538,026	(30,617)	16,735,638	15,095,508	(286,317)	15,066,174	15,922,672	11,283,822	4,083,112	555,739

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.
2/INCLUDES ADJUSTMENTS FOR NON-CASH REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.

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	2017	12,692,958	-	12,692,958	-	96,439	3,082,298	6,390,030
2	2018	253,400	-	12,946,358	45,950	1,956	3,287,793	6,356,477
3	2019	262,050	-	13,208,408	210,750	24,266	3,314,827	6,240,325
4	2020	-	188,713	13,397,121	109,900	33,873	3,359,767	6,236,296
5	2021	-	194,563	13,591,684	117,000	25,268	3,412,062	6,250,622
6	2022	-	199,419	13,791,103	115,200	31,230	3,465,052	6,281,830
7	2023	-	202,949	13,994,052	105,850	34,897	3,527,253	6,378,929
8	2024	-	206,797	14,200,850	116,400	22,730	3,594,920	6,469,327
9	2025	-	210,756	14,411,605	119,050	14,695	3,671,931	6,446,099
10	2026	-	215,497	14,627,102	113,000	21,746	3,752,681	6,548,596
11	2027	-	218,863	14,845,965	99,000	30,873	3,841,671	6,668,459
12	2028	-	223,068	15,069,033	5,274	125,533	3,933,932	6,612,727
13	2029	-	226,543	15,295,576	97,000	37,510	4,025,965	6,726,548
14	2030	-	232,679	15,528,255	73,000	57,564	4,128,080	6,751,949
15	2031	-	237,666	15,765,921	109,940	21,354	4,234,452	6,579,675
16	2032	-	242,244	16,008,165	114,900	13,461	4,348,335	6,158,119
17	2033	-	246,904	16,255,069	68,000	46,404	4,480,835	5,667,061
18	2034	-	252,971	16,508,039	112,000	13,054	4,608,752	5,489,631
19	2035	-	257,499	16,765,538	34,121	61,543	4,770,588	5,545,130
20	2036	-	261,748	17,027,287	51,000	40,921	4,940,415	5,695,879
21	2037	-	265,843	17,293,130	89,000	21,898	5,095,361	5,802,722
22	2038	-	269,568	17,562,698	90,000	17,635	5,257,294	5,927,290
23	2039	-	273,763	17,836,461	78,000	26,311	5,426,746	5,959,053
24	2040	-	277,608	18,114,068	75,000	9,763	5,619,590	6,056,660
25	2041	-	281,120	18,395,188	76,000	36,097	5,788,613	6,261,780
26	2042	-	284,335	18,679,523	26,000	44,604	6,002,344	6,520,115
27	2043	-	288,909	18,968,432	45,229	21,778	6,224,246	6,547,024
28	2044	-	292,755	19,261,187	49,000	12,495	6,455,507	6,790,779
29	2045	-	294,837	19,556,024	50,000	-	6,700,344	7,035,616
30	2046	-	298,117	19,854,141	-	43,083	6,955,377	7,333,733
31	2047	-	301,722	20,155,862	134,000	26,155	7,096,944	7,501,454
32	2048	-	305,856	20,461,718	149,489	2,793	7,250,517	7,588,310
33	2049	-	308,625	20,770,343	-	147,591	7,411,551	7,617,935
34	2050	-	310,888	21,081,231	-	140,328	7,582,111	7,903,823
35	2051	-	312,871	21,394,102	-	132,628	7,762,354	8,185,694
36	2052	-	316,528	21,710,630	-	124,521	7,954,361	8,502,222
37	2053	-	319,592	22,030,222	-	115,870	8,158,084	8,821,814
38	2054	-	322,868	22,353,090	-	106,690	8,374,261	9,144,682
39		**$13,208,408**	**$9,144,682**		**$2,679,053**	**$1,785,555**		

BONNEVILLE POWER ADMINISTRATION

DOE/BP-4814 • July 2017