

BP-22 Rate Proceeding

Initial Proposal

Transmission Revenue Requirement Study

BP-22-E-BPA-09

December 2020



TRANSMISSION REVENUE REQUIREMENT STUDY

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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 “Council”)
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	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)
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-IIIE	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 **1. INTRODUCTION**

2

3 **1.1 Purpose of the Study**

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

18

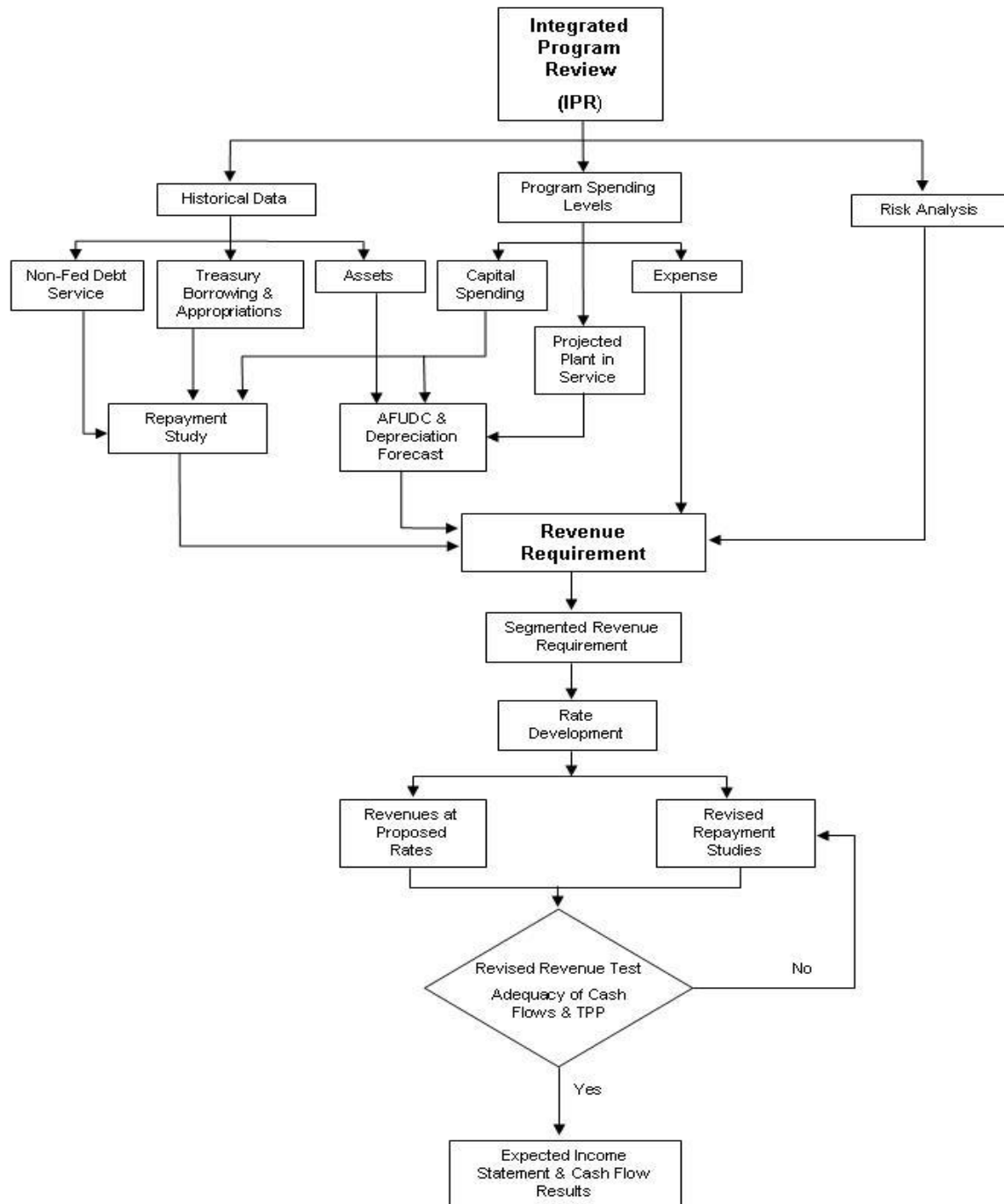
19 The cost evaluation period, as defined by the Federal Energy Regulatory Commission (FERC or
20 Commission), is the period extending from the last year for which historical information is
21 available through the proposed rate period. The cost evaluation period for this initial proposal
22 filing includes Fiscal Year (FY) 2021 and the proposed rate period, FY 2022–2023. This study
23 is based on transmission revenue requirements that include the results of transmission repayment
24 studies. This study does not include the revenue requirement or a cost recovery demonstration
25 for BPA’s power function. *See* Power Revenue Requirement Study, BP-22-E-BPA-02.

1 This Study outlines the policies, forecasts, assumptions, and calculations used to determine the
2 transmission revenue requirement. The Transmission Revenue Requirement Study
3 Documentation, BP-22-E-BPA-09A, contains key technical assumptions and calculations, the
4 results of the transmission repayment studies, and further explanation of the repayment program
5 and its outputs.

6
7 The revenue requirement for this study is developed using a cost accounting analysis comprised
8 of three parts. First, repayment studies for the transmission function are prepared to determine
9 the schedule of amortization payments and to project annual interest expense for bonds and
10 appropriations that fund the Federal investment in transmission and transmission-related assets.
11 Repayment studies are conducted for each year of the rate period and extend over the 35-year
12 repayment period. Second, transmission operating expenses and Minimum Required Net
13 Revenue (MRNR) are projected for each year of the rate period. Third, annual Planned Net
14 Revenues for Risk (PNRR) are determined after taking into account risks, BPA's cost recovery
15 goals, and other risk mitigation measures, as described in the Power and Transmission Risk
16 Study, BP-22-E-BPA-05. From these three steps, the revenue requirement is set at the level
17 necessary to fulfill cost recovery requirements and objectives. This process is depicted in
18 Figure 1, below. Once the revenue requirement is completed, it is segmented and passed to the
19 rate development process, where it is used to develop rates.

20
21 Consistent with Department of Energy (DOE) Order RA 6120.2 and the standards applied by the
22 Commission on review of BPA's rates, BPA must determine the adequacy of both current and
23 proposed rates to recover the revenue requirement. BPA conducts a current revenue test to
24 determine whether revenues projected from current rates meet cost recovery requirements for the
25

Figure 1: Transmission Revenue Requirement Process



1 rate period and the repayment period. If the current revenue test indicates that cost recovery and
2 risk mitigation requirements are met, current rates could be extended through the proposed rate
3 approval period. The current revenue test, described in Section 3.2 of this study, demonstrates
4 that revenues from current rates would be adequate to recover the transmission revenue
5 requirement for the rate period (although other reasons may exist for revising rates).

6
7 The revised revenue test, which is performed after calculation of the proposed transmission rates,
8 determines whether projected revenues from proposed rates meet cost recovery requirements for
9 the rate test and repayment periods. The revised revenue test, Section 3.3 of this study,
10 demonstrates that revenues from the proposed transmission rates will recover transmission costs
11 in the rate period and over the ensuing 35-year repayment period. In addition, revenues from the
12 proposed rates, together with risk mitigation tools, are sufficient to meet BPA's 95 percent
13 Treasury Payment Probability standard that all U.S. Treasury payments will be paid on time and
14 in full, as discussed in the Power and Transmission Risk Study, BP-22-E-BPA-05, § 5.2.4.2.

15
16 Table 1 summarizes the revised revenue test and shows projected net revenues from proposed
17 transmission rates for FY 2022–2023. These net revenues are the lowest level sufficient to
18 achieve, in combination with other risk mitigation tools, BPA's cost recovery objectives in the
19 face of transmission-related risks.

20
21 Table 2 shows planned transmission amortization payments to the U.S. Treasury for each year of
22 the rate period.

1 **1.2 Legal Requirements**

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

6
7 **1.2.1 Governing Authorities**

8 BPA’s revenue requirements are governed primarily by four legislative acts: the Bonneville
9 Project Act of 1937, Pub. L. No. 75-329, 50 Stat. 731, amended 1977; the Flood Control Act of
10 1944, Pub. L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River
11 Transmission System Act of 1974 (Transmission System Act), Pub. L. No. 93-454,
12 88 Stat. 1376, amended 1977; and the Pacific Northwest Electric Power Planning and
13 Conservation Act (Northwest Power Act), Pub. L. No. 96-501, 94 Stat. 2697. The Omnibus
14 Consolidated Rescissions and Appropriations Act of 1996, Pub. L. No. 104-134, 110 Stat. 1321,
15 also guides the development of BPA’s revenue requirements.

16
17 Department of Energy Order “Power Marketing Administration Financial Reporting,”
18 RA 6120.2, issued by the Secretary of Energy, provides guidance to Federal power marketing
19 administrations regarding repayment of the Federal investment. In addition, policies issued by
20 the Commission provide guidance on separate accounting for transmission system costs.
21 *See, e.g., Bonneville Power Admin., 25 FERC ¶ 61,140 (1983).*

22
23 **1.2.1.1 Legal Requirements Governing BPA’s Revenue Requirement**

24 BPA constructs, operates, and maintains the FCRTS within the Pacific Northwest and makes
25 improvements or replacements to the transmission system as are appropriate and required to

1 (a) integrate and transmit electric power from existing or additional Federal or non-Federal
2 generating units; (b) provide service to BPA customers; (c) provide inter-regional transmission
3 facilities; and (d) maintain the electrical stability and reliability of the Federal system.

4 Transmission System Act § 4, 16 U.S.C. § 838b.

5
6 BPA's rates must be set to ensure that revenues are sufficient to recover costs. This requirement
7 was first set forth in Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f , which provides
8 that

9 [r]ate schedules shall be drawn having regard to the recovery (upon the basis of
10 the application of such rate schedules to the capacity of the electric facilities of
11 [the] Bonneville project) of the cost of producing and transmitting such electric
12 energy, including the amortization of the capital investment over a reasonable
13 period of years.

14 This cost recovery principle was repeated for Army reservoir projects in Section 5 of the Flood
15 Control Act of 1944, 16 U.S.C. § 825s. In 1974, Section 9 of the Transmission System Act,
16 16 U.S.C. § 838g, expanded the cost recovery principle so that BPA's rates also would be set to
17 recover

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

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

27 [t]he Administrator shall establish, and periodically review and revise, rates for
28 the sale and disposition of electric energy and capacity and for the transmission of
29 non-Federal power. Such rates shall be established and, as appropriate, revised to
30 recover, in accordance with sound business principles, the costs associated with

1 the acquisition, conservation, and transmission of electric power, including the
2 amortization of the Federal investment in the Federal Columbia River Power
3 System (including irrigation costs required to be repaid out of power revenues)
4 over a reasonable period of years and the other costs and expenses incurred by the
5 Administrator pursuant to this chapter and other provisions of law. Such rates
6 shall be established in accordance with Sections 9 and 10 of the Federal Columbia
7 River Transmission System Act (16 U.S.C. § 838), Section 5 of the Flood Control
8 Act of 1944, and the provisions of this chapter.

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

- 11 1. Are sufficient to assure repayment of the Federal investment in the Federal
12 Columbia River Power System over a reasonable number of years after
13 first meeting the Administrator’s other costs;
- 14 2. Are based upon the Administrator’s total system costs; and
- 15 3. Insofar as transmission rates are concerned, equitably allocate the costs of
16 the Federal transmission system between Federal and non-Federal power
17 utilizing such system.
18

19
20 Development of the revenue requirement is a critical component of meeting the statutory cost
21 recovery principles relevant to BPA. The costs associated with the FCRTS and associated
22 services and expenses, as well as other costs incurred by the Administrator in furtherance of
23 BPA’s mission, are included in the study.

24 25 **1.2.1.2 The BPA Appropriations Refinancing Act**

26 As in the last rate period, BPA’s transmission rates for the FY 2022–23 rate period will reflect
27 the requirements of the Refinancing Act, 16 U.S.C. § 838l, part of the Omnibus Consolidated
28 Rescissions and Appropriations Act of 1996, Pub. L. No. 104-134, 110 Stat. 1321, enacted in
29 April 1996. The Refinancing Act required that unpaid principal on BPA appropriations (“old
30 capital investments”) at the end of FY 1996 be reset at the present value of the principal and
31 annual interest payments BPA would make to the U.S. Treasury for these obligations absent the

1 Refinancing Act, plus \$100 million. 16 U.S.C. § 8381(b). The Refinancing Act also specified
2 that the new principal amounts of the old capital investments be assigned new interest rates from
3 the U.S. Treasury yield curve prevailing at the time of the refinancing transaction. 16 U.S.C.
4 § 8381(a)(6)(A).

5
6 The Refinancing Act restricted prepayment of the new principal for old capital investments to
7 \$100 million during the first five years after the effective date of the financing. 16 U.S.C.
8 § 8381(e). The Refinancing Act also specifies that repayment dates on new principal amounts
9 may not be earlier than the repayment dates for old capital investments. 16 U.S.C. § 8381(d).
10 The Refinancing Act further directs the Administrator to offer to provide assurance in new or
11 existing contracts for power, transmission, or related services that the Government will not
12 increase the repayment obligations in the future. 16 U.S.C. § 8381(i).

13 14 **1.2.2 Repayment Requirements and Policies**

15 **1.2.2.1 Separate Repayment Studies**

16 Section 10 of the Transmission System Act, 16 U.S.C. § 838h, and Section 7(a)(2)(C) of the
17 Northwest Power Act, 16 U.S.C. § 839e(a)(2)(C), provide that the recovery of the costs of the
18 Federal transmission system shall be equitably allocated between Federal and non-Federal power
19 utilizing such system. In 1982, the Commission first directed BPA to provide accounting and
20 repayment statements for its transmission system separate and apart from the accounting and
21 repayment statements for the Federal generation system. *Bonneville Power Admin.*, 20 FERC
22 ¶ 61,142 (1982). The Commission required BPA to establish books of account for the FCRTS
23 separate from its generation books of account; explained that the FCRTS shall be comprised of
24 all investments, including administrative and management costs, related to the transmission of
25 electric power; and directed BPA to develop repayment studies for its transmission function

1 separate from those for its generation function. Such studies must set forth the date of each
2 investment, the repayment date, and the amount repaid from transmission revenues. *Bonneville*
3 *Power Admin.*, 26 FERC ¶ 61,096 (1984).

4
5 The Commission approved BPA’s methodology for separate repayment studies in 1984.
6 *Bonneville Power Admin.*, 28 FERC ¶ 61,325 (1984). Thus, BPA has prepared separate
7 repayment studies for its transmission and generation functions since 1984. This methodology
8 has enabled BPA to set power and transmission rates separately with minimal change in
9 repayment policy and the process for developing each revenue requirement. This study
10 incorporates only the repayment study for the transmission function for FY 2022–2023.

11 12 **1.2.2.2 Repayment Schedules**

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

17
18 There have been a number of changes in BPA’s repayment policy over the years concurrent with
19 expansion of the Federal system and changing conditions. In general, current repayment criteria
20 were approved by the Secretary of the Interior on April 3, 1963. These criteria were refined and
21 submitted to the Secretary and the Federal Power Commission (the predecessor agency to the
22 Federal Energy Regulatory Commission) in support of BPA’s rate filing in September 1965.

23
24 The repayment policy was presented to Congress for its consideration for the authorization of the
25 Grand Coulee Dam Third Powerhouse in June 1966. The underlying theory of repayment was

1 discussed in the House of Representatives' report related to authorization of this project,
2 H.R. Rep. No. 89-1409, 2d Sess., at 9-10 (1966). As stated in that report:

3 Accordingly, [in a repayment study] there is no annual schedule of capital
4 repayment. The test of the sufficiency of revenues is whether the capital
5 investment can be repaid within the overall repayment period established for each
6 power project, each increment of investment in the transmission system, and each
7 block of irrigation assistance. Hence, repayment may proceed at a faster or
8 slower pace from year-to-year as conditions change. . . .

9 This approach to repayment scheduling has the effect of averaging the year-to-year variations in
10 costs and revenues over the repayment period. This results in a uniform cost per unit of power
11 sold, and permits the maintenance of stable rates for extended periods. It also facilitates the
12 orderly marketing of power and permits BPA customers, which include both electric utilities and
13 electroprocess industries, to plan for the future with assurance.

14
15 The Secretary of the Interior issued a statement of power policy on September 30, 1970, setting
16 forth general principles that reaffirmed the repayment policy as previously developed. The most
17 pertinent of these principles were set forth in the Department of the Interior Manual, Part 730,

18 Chapter 1:

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

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

8
9 A further clarification of the repayment policy was outlined in a joint memo on January 7, 1974,
10 from the Assistant Secretary for Reclamation and Assistant Secretary for Energy and Minerals.
11 This memo states that in addition to meeting the overall objective of repaying the Federal
12 investment and obligations within the prescribed repayment periods, revenues shall be adequate,
13 except in unusual circumstances, to repay annually all costs for O&M, purchased power, and
14 interest.

15
16 On March 22, 1976, the DOI issued Chapter 4 of Part 730 of the DOI Manual to codify financial
17 reporting requirements for the Federal power marketing administrations; it describes standard
18 policies and procedures for preparing system repayment studies.

19
20 BPA and the other Federal power marketing agencies were transferred to the newly established
21 Department of Energy on October 1, 1977. Department of Energy Organization Act, 42 U.S.C.
22 § 7101 *et seq.* The DOE adopted the policies set forth in Part 730 of the DOI Manual by issuing
23 Interim Management Directive No. 1701 on September 28, 1977, which subsequently was
24 replaced by RA 6120.2, issued on September 20, 1979, and amended on October 1, 1983.

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

- 3 1. Pay all annual costs of operating and maintaining the Federal power
4 system;
- 5 2. Pay the cost of obtaining power through purchase and exchange
6 agreements, the cost for transmission services, and other costs during the
7 year in which such costs are incurred;
- 8 3. Pay interest each year on the unamortized portion of the commercial
9 power investment financed with appropriated funds at the interest rates
10 established for each generating project and for each annual increment of
11 such investment in the BPA transmission system, except that recovery of
12 annual interest expense may be deferred in unusual circumstances for
13 short periods of time;
- 14 4. Pay when due the interest and amortization portion on outstanding bonds
15 sold to the U.S. Treasury;
- 16 5. Repay:
 - 17 • each dollar of power investments and obligations in the FCRPS
18 generating projects within 50 years after the projects become
19 revenue-producing (50 years has been deemed a "reasonable
20 period" as intended by Congress, except for the Yakima-Chandler
21 Project, which has a legislated amortization period of 66 years);
 - 22 • each annual increment of transmission financed by Federal
23 investments and obligations within the average service life of such
24 transmission facilities (currently 40 years) or within a maximum of
25 50 years, whichever is less (BPA has interpreted RA 6120.2 to

1 require repayment of bonds sold to finance conservation to be
2 within the average service lives of these projects, currently
3 estimated to be five years, and for fish and wildlife facilities to be
4 15 years);

- 5 • the federally financed amount of each replacement within its
6 service life up to a maximum of 50 years; and

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

12
13 The typical repayment period for appropriated capital investments for generation is 50 years
14 from the year in which the plant is placed in service. Due dates for appropriated transmission
15 investments were set at no more than 45 years. The Refinancing Act (Section 1.2.1.2) overrides
16 provisions in DOE Order RA 6120.2 related to determining interest during construction and
17 assigning interest rates to Federal investments financed by appropriations. This Act also
18 contains provisions on repayment periods (due dates) for the refinanced investments.

19
20 Other sections within DOE Order RA 6120.2 require that any outstanding deferred interest
21 payments must be repaid before any planned amortization payments are made. Also, repayments
22 are to be made by amortizing those Federal investments and obligations bearing the highest
23 interest rate first, to the extent possible, while ensuring that BPA still completes repayment of
24 each increment of Federal investment and obligation within its prescribed repayment period.

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1 includes forecasts of net interest expense and depreciation and amortization expense, which
2 includes amortization of the terminated I-5 reinforcement project.

3
4 After considering the comments received, BPA released a final IPR close-out report in
5 September 2020.

6
7 This study incorporates the spending levels identified in the 2020 IPR and CIR final close-out
8 report, which can be found on BPA’s public website:

9 <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2020.aspx>

11 **2.2 Capital Investments**

12 The forecast of BPA’s capital investments for FY 2022–2023 used in developing the BP-22
13 transmission initial proposal rates was produced from the CIR levels in the IPR/CIR close-out
14 reports. The following section describes the capital investment forecasts.

15
16 BPA transmission capital spending projections including allowance for funds used during
17 construction (AFUDC) for the FY 2022–2023 rate period are \$1.09 billion. Rounded, these
18 investments are:

- 19 • Transmission programs (\$1.06 billion)
- 20 • Environmental program (\$13.4 million)
- 21 • Corporate capital program (\$13.3 million)

22 Transmission Revenue Requirement Study Documentation, BP-22-E-BPA-09A, Table 7-2.

24 **2.2.1 Bonds Issued to the Treasury**

25 Bonds issued to the U.S. Treasury will be the primary source of capital used to finance projected
26 FY 2022–2023 transmission capital program investments. Interest rates on bonds issued by BPA

1 to the U.S. Treasury are set at market interest rates comparable to the interest rates for securities
2 issued by other agencies of the U.S. Government. For interest rates on bonds projected to be
3 issued, *see id.*, Ch. 6.
4

5 **2.2.2 Federal Appropriations**

6 All Congressional Appropriations related to the Transmission system have been fully repaid. As
7 a result, the repayment study no longer includes any obligation to repay appropriations.
8

9 **2.2.3 Revenues for Capital Investment**

10 As a means to fund capital investments in lieu of borrowing, the revenue requirement assumes
11 that \$45 million per year of the capital program is funded with current revenues.
12

13 **2.2.4 Non-Federal Payment Obligations**

14 The transmission revenue requirements reflect two forms of non-Federal payment obligations.
15 The first is lease purchase arrangements for assets. BPA entered into its first transaction in 2004
16 with the Northwest Infrastructure Financing Corporation (NIFC), a subsidiary of
17 JH Management, to provide for the construction of the 500-kV Schultz-Wautoma transmission
18 line (Schultz-Wautoma line). Since the completion of the Schultz-Wautoma project, BPA has
19 entered into additional lease financing arrangements with NIFC, Port of Morrow, and Idaho
20 Energy Resources Authority. BPA constructs the facilities financed by the lease holder. BPA
21 makes periodic lease payments. During the term of the lease, BPA operates the facilities. At the
22 end of the lease, BPA has an option to purchase the facilities for a nominal fee. The revenue
23 requirement includes all transactions BPA expects to complete by the date of the Final Proposal.
24 BPA does not currently anticipate entering into new lease purchase arrangements in the
25 rate period.

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

13
14 For specific calculations regarding non-Federal payment obligations, *see id.*, Ch. 8.

15 16 **2.2.5 Customer-Financed Projects**

17 The revenue requirements also reflect the impacts of customer-financed projects. Customers
18 have financed capital construction projects under generation interconnection agreements (LGIA
19 or SGIA). BPA amended its Open Access Transmission Tariff and adopted the LGIA and SGIA
20 in voluntary compliance with Commission Order Nos. 2003 and 2006. Under the generator
21 interconnection agreements, interconnection customers finance the cost of Network Upgrades
22 (facilities at or beyond the point at which the customer's interconnection facilities connect to
23 BPA's transmission system) needed to interconnect their generating facilities to BPA's
24 transmission system if BPA, as the transmission owner/provider, does not provide the funding.
25 BPA requires the interconnection customer to advance funds in an amount sufficient to cover the

1 cost of construction. These advance funds, with interest on the outstanding balance, are then
2 returned to the interconnection customer in the form of transmission credits. These credits either
3 offset charges for eligible transmission service in the customer's bill or are provided as monthly
4 cash payments based on the generating facility's capacity and its plant capacity factor.

5
6 These customer-financed transactions and the associated transmission credits affect several areas
7 of the revenue requirement. Depreciation of the associated assets appears in total transmission
8 depreciation. The interest that accrues on the outstanding credit balances is included in non-
9 Federal interest, a component of the net interest calculation on the income statement. Both of
10 these items increase transmission expenses. These items also appear in the statement of cash
11 flows, because they are non-cash expenses. In addition, the revenues associated with customer-
12 financed projects for which customers receive credits affect the statement of cash flows because
13 they are non-cash revenues—they provide no cash for cost recovery. Therefore, they generally
14 increase the need for MRNR, which is added to the income statement if necessary, to ensure that
15 all cash requirements are met.

16
17 Non-cash expenses (depreciation and interest on outstanding credit balances) offset non-cash
18 revenues and decrease the need for MRNR. The non-cash expenses are subtracted from the non-
19 cash revenues. If the difference is positive, meaning that non-cash revenues exceed non-cash
20 expenses, the need for MRNR increases. If the difference is negative, meaning that non-cash
21 expenses exceed non-cash revenues, the need for MRNR decreases.

22 23 **2.3 Modeling of BPA's Repayment Obligations**

24 Repayment studies are performed as part of the process for determining revenue requirements.
25 The studies establish a schedule of annual U.S. Treasury amortization for the rate period and the

1 resulting interest payments. Each repayment study covers a rate test year and the ensuing
2 repayment period, which extends to the last year by which all outstanding and projected
3 obligations must be repaid. For transmission repayment studies, that period is 35 years. This
4 study horizon reflects the fact that bonds are not issued for terms longer than 35 years and that
5 the outstanding appropriations and bonds that finance the transmission system are fully repaid
6 within this period. This study horizon is also appropriate in that it does not exceed the estimated
7 average service life of transmission system plant (45 years).

8
9 In conducting the repayment studies, BPA includes as fixed inputs the annual debt service
10 payments associated with its non-federal capitalized contract obligations and the fixed annual
11 payments associated with long-term energy resource acquisition contracts. All outstanding and
12 projected transmission repayment obligations for appropriated investments and bonds issued to
13 the U.S. Treasury are included to be scheduled for repayment. Forecast transmission repayment
14 obligations related to the lease purchase program are also modeled and scheduled for repayment.
15 Funding for replacements projected during the repayment period is also included in the
16 repayment study, consistent with the requirements of DOE Order RA 6120.2.

17
18 Appropriations and bonds are scheduled to be repaid within the expected useful life of the
19 associated facility, or the maximum repayment period (50 years for generation and 35 years for
20 transmission), whichever is less. Bonds issued by BPA to the U.S. Treasury have varying terms,
21 taking into account the estimated average service lives for investments and prudent financing and
22 cash management factors. Projected lease purchase obligations assumed in the repayment study
23 are held to the same parameters.

1 In the repayment studies, all projected bonds are issued with maturities not to exceed 30 years
2 for transmission investment, although they can be refinanced within the 35-year repayment
3 period. Environmental investments have a maximum term of 15 years. Corporate investments,
4 generally for information technology, are for a five-year period. Generally bonds are issued with
5 a provision that allows the bonds to be called any time. Bonds also may be issued with
6 provisions such as a five-year call or a no call provision. Early retirement of eligible bonds may
7 require that BPA pay a bond premium to the Treasury. Bonds may also be called and repaid at a
8 discount. Bonds are issued to finance BPA transmission, environment, and corporate
9 investments and are repaid within the provisions of each bond agreement with the Treasury.

10
11 Based on these parameters, the repayment study establishes a schedule of planned amortization
12 payments and resulting interest expense by determining the lowest levelized debt service stream
13 necessary to repay all transmission obligations within the required repayment period.

14 For further discussion of the repayment program, *see* Transmission Revenue Requirement Study
15 Documentation, BP-22-E-BPA-09A, Ch. 14.

16 17 **2.4 Products Used by Other Studies**

18 This study produces the segmented revenue requirement, which allocates transmission costs
19 among transmission segments. Chapter 2 of the documentation for this study describes the
20 segmentation of the revenue requirement in detail. *Id.*, Ch. 2.2. The segmented revenue
21 requirement is used in the Transmission Rates Study and Documentation to develop rates for the
22 various transmission products. More detail on the transmission segments is available in the
23 Transmission Segmentation Study and Documentation, BP-22-E-BPA-07.

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1 cash (line 26). The MRNR amount shown on the Statement of Cash Flows (line 2) then is
2 incorporated in the Income Statement (Table 3, line 27).

3 4 **3.2 Current Revenue Test**

5 Consistent with DOE Order RA 6120.2, the continuing adequacy of existing rates must be tested
6 annually. The current revenue test, exhibited in Tables 5 and 6, determines whether the revenue
7 expected from current rates will meet cost recovery requirements during the FY 2022–2023 rate
8 period and the ensuing repayment period. For revenue at current rates, *see* Transmission Rate
9 Study and Documentation, BP-22-E-BPA-08, Table 12.

10
11 The result of the current revenue test demonstrates that projected revenue from current rates is
12 inadequate to meet the cost recovery criteria of Order RA 6120.2 because the net position is
13 negative in the rate period and for some years of the repayment period. *See* Table 7, column K.
14 This means that current rates could not be extended.

15 16 **3.3 Revised Revenue Test**

17 Consistent with DOE Order RA 6120.2, the adequacy of proposed rates must be demonstrated.
18 The revised revenue test determines whether the revenue projected from proposed rates will meet
19 cost recovery requirements for the rate period. The revised revenue test is conducted using the
20 forecast of revenue under proposed rates. Transmission Rate Study and Documentation, BP-22-
21 E-BPA-08, Table 12.

22
23 For the rate period, the demonstration of the adequacy of proposed rates is shown in Tables 8
24 and 9. Table 9 tests the sufficiency of the resulting net revenues from Table 8, line 23, for
25 making the planned annual amortization payments. The sufficiency of net revenues is

1 demonstrated by the annual increase (or decrease) in cash (Table 9, line 25). The annual cash
2 flow must be at least zero to demonstrate the adequacy of the projected revenues to cover all
3 cash requirements.

4
5 The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill cost
6 recovery requirements for the rate period, FY 2022–2023. With the successful test of proposed
7 rates, the rate development process ends.

8 9 **3.4 Repayment Test at Proposed Rates**

10 Table 10, Transmission Revenues from Proposed Rates, demonstrates whether projected revenue
11 from proposed rates is adequate to meet the cost recovery criteria of DOE Order RA 6120.2 over
12 the repayment period. The data are presented in a format consistent with the revised revenue
13 tests, Tables 8 and 9, and the separate accounting analysis that is an attachment to the rate filing
14 BPA submits to the Commission. The focal point of Table 10 is the net position (column K),
15 which is the amount of funds provided by revenues that remain after meeting annual expenses
16 requiring cash for the rate period and repayment of the Federal investment. Thus, if the net
17 position is zero or greater in each of the years of the rate period through the repayment period,
18 the projected revenues demonstrate BPA’s ability to repay the Federal investment in the FCRPS
19 within the allowable time. As shown in column K, the resulting net position is zero or greater for
20 each year of the rate period and in each year of the repayment period.

21
22 The historical data on this table have been taken from BPA’s separate accounting analysis. The
23 rate period data have been developed specifically for this study. The repayment period data are
24 presented consistent with the requirements of DOE Order RA 6120.2.

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

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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	1,204,495	1,212,570	1,208,532
2 PROJECTED EXPENSES	<u>1,140,875</u>	<u>1,161,791</u>	<u>1,151,333</u>
3 NET REVENUES	63,620	50,779	57,199

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

		A	B	C
		BOND	APPROPRIATIONS	
		AMORTIZATION	AMORTIZATION	TOTAL
1	2022	219,399	-	219,399
2	2023	<u>222,680</u>	-	<u>222,680</u>
3	TOTAL	442,079	-	442,079

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

	A	B
	2022	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	129,727	130,408
6 BPA INTERNAL SUPPORT	102,667	104,141
7 OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
8 DEPRECIATION & AMORTIZATION	351,035	355,917
9 TOTAL OPERATING EXPENSES	986,798	999,556
10		
11		
12 INTEREST EXPENSE		
13 INTEREST EXPENSE		
14 FEDERAL APPROPRIATIONS	-	-
15 CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
16 ON LONG-TERM DEBT	117,011	130,251
17 AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
18 DEBT SERVICE REASSIGNMENT INTEREST	2,960	1,927
19 NON-FEDERAL INTEREST (INCL CUSTOMER FUNDED)	70,116	67,749
20 PREMIUMS/DISCOUNTS	-	-
21 AFUDC	(14,937)	(16,369)
22 INTEREST INCOME	(2,662)	(2,915)
23 NET INTEREST EXPENSE	154,078	162,235
24		
25 TOTAL EXPENSES	1,140,875	1,161,791
26		
27 TOTAL MINIMUM REQUIRED NET REVENUE 1/	56,048	57,919
28 PLANNED NET REVENUES FOR RISK	-	-
29 TOTAL PLANNED NET REVENUE	56,048	57,919
30		
31 TOTAL REVENUE REQUIREMENT	1,196,923	1,219,710

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	56,048	57,919
3 EXPENSES NOT REQUIRING CASH:		
4 DEPRECIATION & AMORTIZATION	351,035	355,917
5 CUSTOMER FUNDED PROJECTS NET INTEREST	2,845	2,112
6 AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
7 CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8 NON-CASH REVENUES		
9 CUSTOMER FUNDED	(28,031)	(30,487)
10 AC INTERTIE CO/FIBER	(3,482)	(3,482)
11 CASH PROVIDED BY CURRENT OPERATIONS	360,005	363,571
12		
13 CASH USED FOR CAPITAL INVESTMENTS:		
14 INVESTMENT IN:		
15 UTILITY PLANT	(526,591)	(560,003)
16 CASH USED FOR CAPITAL INVESTMENTS	(526,591)	(560,003)
17		
18 CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
19 INCREASE IN LONG-TERM DEBT	481,591	515,003
20 DEBT SERVICE REASSIGNMENT PRINCIPAL	(21,596)	(22,678)
21 REPAYMENT OF CAPITAL LEASES	(74,010)	(73,212)
22 REPAYMENT OF LONG-TERM DEBT	(219,399)	(222,680)
23 REPAYMENT OF CAPITAL APPROPRIATIONS	-	-
24 CASH FROM TREASURY BORROWING AND APPROP.	166,586	196,432
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	B
		FY 2022	FY 2023
1	REVENUES FROM CURRENT RATES	1,086,091	1,094,753
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	169,239	172,135
4	TRANSMISSION ENGINEERING	56,570	57,094
5	TRANSMISSION MAINTENANCE	177,560	179,860
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	129,727	130,408
7	BPA INTERNAL SUPPORT	102,667	104,141
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
9	DEPRECIATION & AMORTIZATION	<u>351,035</u>	<u>355,917</u>
10	TOTAL OPERATING EXPENSES	986,798	999,556
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	-	-
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	117,011	130,251
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
17	DEBT SERVICE REASSIGNMENT INTEREST	2,960	1,927
18	NON-FEDERAL INTEREST	70,116	67,749
17	PREMIUMS/DISCOUNTS	-	-
19	AFUDC	(14,937)	(16,369)
20	INTEREST INCOME	<u>(2,318)</u>	<u>(1,751)</u>
21	NET INTEREST EXPENSE	154,422	163,399
22	TOTAL EXPENSES	1,141,219	1,162,955
23	NET REVENUES	(55,128)	(68,202)

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

	A	B	C	D	E	F	G	H	I	J	K	
	REVENUES	OPERATION & MAINTENANCE	DEBT SERVICE OFFSETS		NET INTEREST	NET REVENUES	NONCASH EXPENSES 1/	FUNDS FROM OPERATION 2/	AMORTIZATION	NON-FEDERAL PRINCIPAL	NET POSITION	
	(STATEMENT A)	(STATEMENT E)	(REV REQ STUDY DOC)	DEPRECIATION	(TABLE D)	(F=A-B-C-D-E)	(COLUMN D)	(H=F+G)	(REV REQ STUDY DOC, Chapter 10)	(REV REQ STUDY DOC, Chapter 7)	(K=H-I-J)	
YEAR												
COMBINED CUMULATIVE												
1	Thru 2015	24,961,478	11,059,061	348,748	5,719,577	6,638,882	1,195,210	5,284,623	7,472,648	6,435,803	586,532	450,314
	2016	1,061,700	563,907		244,158	136,358	117,277	231,397	563,674	383,410	186,696	(6,432)
2	2017	1,091,725	600,846		260,927	139,499	90,453	248,168	317,521	96,439	201,768	19,314
3	2018	1,090,198	596,564		286,284	140,788	66,562	272,676	316,184	47,906	193,402	74,876
4	2019	1,058,112	611,395	0	306,000	148,210	(7,493)	256,172	(80,546)	235,016	17,304	(332,865)
5	2020	1,052,020	548,238	0	335,807	164,026	3,949	298,698	279,647	199,699	98,999	(19,051)
6												
7	COST EVALUATION PERIOD											
8	2021	1,107,214	560,240	-	341,867	178,665	26,442	304,601	304,601	204,438	100,163	1
9												
10												
11	RATE APPROVAL PERIOD											
12	2022	1,086,091	635,763	-	351,035	154,422	(55,128)	303,957	203,828	219,399	95,606	(111,177)
13	2023	1,094,753	643,639	-	355,917	163,399	(68,202)	305,651	192,449	222,680	95,891	(126,122)
14												
15												
16	REPAYMENT PERIOD											
17	2024	1,094,753	643,639	(7,762)	355,917	192,489	(89,531)	308,285	218,754	192,209	108,628	(82,082)
18	2025	1,094,753	643,639	(7,762)	355,917	193,103	(90,145)	308,285	218,140	188,988	109,338	(80,187)
19	2026	1,094,753	643,639	(7,762)	355,917	186,764	(83,806)	308,285	224,479	191,922	109,944	(77,386)
20	2027	1,094,753	643,639	(7,762)	355,917	184,203	(81,244)	308,285	227,041	207,227	87,469	(67,656)
21	2028	1,094,753	643,639	(7,762)	355,917	180,687	(77,729)	308,285	230,556	213,480	76,856	(59,779)
22	2029	1,094,753	643,639	(7,762)	355,917	178,752	(75,794)	308,285	232,491	294,867	1,944	(64,319)
23	2030	1,094,753	643,639	(7,762)	355,917	177,372	(74,414)	308,285	233,871	301,824	2,050	(70,004)
24	2031	1,094,753	643,639	(7,762)	355,917	171,684	(68,726)	308,285	239,559	310,830	2,169	(73,439)
25	2032	1,094,753	643,639	(7,762)	355,917	163,377	(60,419)	308,285	247,866	317,272	2,294	(71,700)
26	2033	1,094,753	643,639	(7,762)	355,917	160,594	(57,636)	308,285	250,649	318,901	2,427	(70,679)
27	2034	1,094,753	643,639	(7,762)	355,917	152,536	(49,578)	308,285	258,707	317,395	104,031	(62,720)
28	2035	1,094,753	643,639	(7,762)	355,917	147,309	(44,351)	308,285	263,934	319,263	127,545	(54,874)
29	2036	1,094,753	643,639	(7,762)	355,917	135,460	(32,502)	308,285	275,783	319,087	127,695	(42,998)
30	2037	1,094,753	643,639	(7,762)	355,917	133,307	(30,349)	308,285	277,936	321,652	97,263	(40,980)
31	2038	1,094,753	643,639	(7,762)	355,917	119,558	(16,600)	308,285	291,685	323,200	97,431	(28,946)
32	2039	1,094,753	643,639	(7,762)	355,917	114,920	(11,962)	308,285	296,323	320,583	97,609	(21,870)
33	2040	1,094,753	643,639	(7,762)	355,917	118,009	(15,051)	308,285	293,234	327,326	97,793	(31,886)
34	2041	1,094,753	643,639	(7,762)	355,917	119,445	(16,486)	308,285	291,799	329,554	103,589	(41,343)
35	2042	1,094,753	643,639	(7,762)	355,917	115,302	(12,344)	308,285	295,941	333,704	88,541	(26,303)
36	2043	1,094,753	643,639	(7,762)	355,917	103,954	(996)	308,285	307,289	340,212	103,733	(6,656)
37	2044	1,094,753	643,639	(7,762)	355,917	94,968	7,991	308,285	316,276	344,720	102,084	(529)
38	2045	1,094,753	643,639	(7,762)	355,917	81,443	21,515	308,285	329,800	346,975	92,676	10,149
39	2046	1,094,753	643,639	(7,762)	355,917	68,635	34,323	308,285	342,608	348,872	111,171	20,566
40	2047	1,094,753	643,639	(7,762)	355,917	55,495	47,463	308,285	355,748	342,417	83,086	30,245
41	2048	1,094,753	643,639	(7,762)	355,917	41,706	61,252	308,285	369,537	328,115	2,202	39,220
42	2049	1,094,753	643,639	(7,762)	355,917	27,197	75,761	308,285	384,046	331,482	2,325	50,239
43	2050	1,094,753	643,639	(7,762)	355,917	11,932	91,026	308,285	399,311	334,990	2,455	61,867
44	2051	1,094,753	643,639	(7,762)	355,917	(4,129)	107,087	308,285	415,372	338,643	2,593	74,137
45	2052	1,094,753	643,639	(7,762)	355,917	(21,027)	123,985	308,285	432,270	342,447	2,737	87,086
46	2053	1,094,753	643,639	(7,762)	355,917	(32,270)	135,228	308,285	443,513	346,409	2,890	94,214
47	2054	1,094,753	643,639	(7,762)	355,917	(34,842)	137,800	308,285	446,085	350,536	3,052	92,497
48	2055	1,094,753	643,639	(7,762)	355,917	(34,842)	137,800	308,285	446,085	354,835	3,222	88,028
49	2056	1,094,753	643,639	(7,762)	355,917	(34,842)	137,800	308,285	446,085	359,311	3,402	83,372
50	2057	1,094,753	643,639	(7,762)	355,917	(34,842)	137,800	308,285	446,085	363,974	3,593	78,519
51	2058	1,094,753	643,639	(7,762)	355,917	(34,842)	137,800	308,285	446,085	368,830	3,793	73,462
52												
53												
54	TRANSMISSION TOTALS	69,864,834	36,389,911	425,842	20,032,537	11,554,102	1,462,442	17,795,857	20,134,672	17,128,832	2,847,823	158,017
55												

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	B
		FY 2022	FY 2023
1	REVENUES FROM PROPOSED RATES	1,204,495	1,212,570
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	169,239	172,135
4	TRANSMISSION ENGINEERING	56,570	57,094
5	TRANSMISSION MAINTENANCE	177,560	179,860
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	129,727	130,408
7	BPA INTERNAL SUPPORT	102,667	104,141
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	-	-
9	DEPRECIATION & AMORTIZATION	<u>351,035</u>	<u>355,917</u>
10	TOTAL OPERATING EXPENSES	986,798	999,556
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	-	-
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	117,011	130,251
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
17	DEBT SERVICE REASSIGNMENT INTEREST	2,960	1,927
18	NON-FEDERAL INTEREST	70,116	67,749
19	PREMIUMS/DISCOUNTS	-	-
19	AFUDC	(14,937)	(16,369)
20	INTEREST INCOME	<u>(2,662)</u>	<u>(2,915)</u>
21	NET INTEREST EXPENSE	154,078	162,235
22	TOTAL EXPENSES	1,140,875	1,161,791
23	NET REVENUES	63,620	50,779

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

		A	B
		FY 2022	FY 2023
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	63,620	50,779
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	-	-
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	351,035	355,917
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	2,845	2,112
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES		
10	LGIA	(28,031)	(30,487)
11	AC INTERTIE CO/FIBER	(3,482)	(3,482)
12	CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION	<u>(7,356)</u>	<u>7,356</u>
13	CASH PROVIDED BY CURRENT OPERATIONS	360,220	363,786
14	CASH USED FOR CAPITAL INVESTMENTS:		
15	INVESTMENT IN:		
16	UTILITY PLANT	<u>(526,591)</u>	<u>(560,003)</u>
17	CASH USED FOR CAPITAL INVESTMENTS	(526,591)	(560,003)
18	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
19	INCREASE IN LONG-TERM DEBT	481,591	515,003
20	DEBT SERVICE REASSIGNMENT PRINCIPAL	(21,596)	(22,678)
21	REPAYMENT OF CAPITAL LEASES	(74,010)	(73,212)
22	REPAYMENT OF LONG-TERM DEBT	(219,399)	(222,680)
23	REPAYMENT OF CAPITAL APPROPRIATIONS	<u>-</u>	<u>-</u>
24	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	166,586	196,432
25	ANNUAL INCREASE (DECREASE) IN CASH	216	215
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
			DEBT SERVICE OFFSETS		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 10)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC, Chapter 7)	NET POSITION (K=H-I-J)
YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	(REV REQ STUDY DOC)	DEPRECIATION							
COMBINED CUMULATIVE											
1 Thru 2015	24,961,478	11,059,061	348,748	5,719,577	6,638,882	1,195,210	5,284,623	7,472,648	6,435,803	586,532	450,314
2 2016	1,061,700	563,907		244,158	136,358	117,277	231,397	563,674	383,410	186,696	(6,431)
3 2017	1,091,725	600,846		260,927	139,499	90,453	248,168	317,521	46,439	201,768	19,314
4 2018	1,090,198	596,564		286,284	140,788	66,562	272,676	316,184	47,906	193,402	74,876
5 2019	1,058,112	611,395	-	306,000	148,210	(7,493)	256,172	(80,546)	235,016	17,304	(332,865)
6 2020	1,094,215	560,239	-	339,833	164,169	29,975	298,698	260,709	205,000	100,670	(44,962)
7											
8 COST EVALUATION PERIOD											
9 2021	1,107,214	560,240	-	341,867	178,665	26,442	304,601	304,601	204,438	100,163	1
10											
11											
12 RATE APPROVAL PERIOD											
13											
14 2022	1,204,495	635,763	-	351,035	154,078	63,620	296,601	315,220	219,399	95,606	216
15 2023	1,212,570	643,639	-	355,917	162,235	50,779	313,007	318,786	222,680	95,891	215
16											
17 REPAYMENT PERIOD											
18 2024	1,212,570	643,639	(7,762)	355,917	148,442	72,333	315,641	387,974	192,209	108,628	87,138
19 2025	1,212,570	643,639	(7,762)	355,917	157,104	63,671	315,641	379,312	188,988	109,338	80,985
20 2026	1,212,570	643,639	(7,762)	355,917	189,381	31,394	315,641	347,035	191,922	109,944	45,170
21 2027	1,212,570	643,639	(7,762)	355,917	194,030	26,745	315,641	342,386	207,227	87,469	47,690
22 2028	1,212,570	643,639	(7,762)	355,917	191,217	29,558	315,641	345,199	213,480	76,856	54,864
23 2029	1,212,570	643,639	(7,762)	355,917	190,813	29,963	315,641	345,604	294,867	1,944	48,793
24 2030	1,212,570	643,639	(7,762)	355,917	192,063	28,712	315,641	344,353	301,824	2,050	40,479
25 2031	1,212,570	643,639	(7,762)	355,917	177,668	43,107	315,641	358,748	310,830	2,169	45,750
26 2032	1,212,570	643,639	(7,762)	355,917	169,192	51,583	315,641	367,224	317,272	2,294	47,658
27 2033	1,212,570	643,639	(7,762)	355,917	168,320	52,455	315,641	368,096	318,901	2,427	46,768
28 2034	1,212,570	643,639	(7,762)	355,917	163,580	57,195	315,641	372,836	217,395	104,031	51,410
29 2035	1,212,570	643,639	(7,762)	355,917	161,808	58,967	315,641	374,608	191,263	127,545	55,801
30 2036	1,212,570	643,639	(7,762)	355,917	162,049	58,726	315,641	374,367	191,087	127,695	55,586
31 2037	1,212,570	643,639	(7,762)	355,917	164,755	56,021	315,641	371,662	221,652	97,263	52,746
32 2038	1,212,570	643,639	(7,762)	355,917	164,777	55,998	315,641	371,639	223,200	97,431	51,008
33 2039	1,212,570	643,639	(7,762)	355,917	164,526	56,249	315,641	371,890	220,583	97,609	53,697
34 2040	1,212,570	643,639	(7,762)	355,917	163,036	57,739	315,641	373,380	227,326	97,793	48,261
35 2041	1,212,570	643,639	(7,762)	355,917	164,766	56,009	315,641	371,650	229,554	103,589	38,508
36 2042	1,212,570	643,639	(7,762)	355,917	166,534	54,241	315,641	369,882	233,704	88,541	47,637
37 2043	1,212,570	643,639	(7,762)	355,917	169,082	51,693	315,641	367,335	210,212	103,733	53,389
38 2044	1,212,570	643,639	(7,762)	355,917	170,629	50,146	315,641	365,787	214,720	102,084	48,983
39 2045	1,212,570	643,639	(7,762)	355,917	169,495	51,280	315,641	366,921	226,975	92,676	47,270
40 2046	1,212,570	643,639	(7,762)	355,917	166,614	54,161	315,641	369,802	210,872	111,171	47,760
41 2047	1,212,570	643,639	(7,762)	355,917	163,723	57,052	315,641	372,693	242,417	83,086	47,190
42 2048	1,212,570	643,639	(7,762)	355,917	161,386	59,389	315,641	375,031	328,115	2,202	44,713
43 2049	1,212,570	643,639	(7,762)	355,917	157,813	62,962	315,641	378,603	331,482	2,325	44,796
44 2050	1,212,570	643,639	(7,762)	355,917	152,701	68,074	315,641	383,715	334,990	2,455	46,270
45 2051	1,212,570	643,639	(7,762)	355,917	149,205	71,570	315,641	387,211	338,643	2,593	45,976
46 2052	1,212,570	643,639	(7,762)	355,917	145,562	75,213	315,641	390,854	342,447	2,737	45,670
47 2053	1,212,570	643,639	(7,762)	355,917	141,765	79,010	315,641	394,651	346,409	2,890	45,351
48 2054	1,212,570	643,639	(7,762)	355,917	137,809	82,966	315,641	398,607	350,536	3,052	45,018
49 2055	1,212,570	643,639	(7,762)	355,917	133,687	87,088	315,641	402,729	354,835	3,222	44,672
50 2056	1,212,570	643,639	(7,762)	355,917	129,391	91,384	315,641	407,025	359,311	3,402	44,311
51 2057	1,212,570	643,639	(7,762)	355,917	124,915	95,860	315,641	411,501	363,974	3,593	43,934
52 2058	1,212,570	643,639	(7,762)	355,917	120,251	100,525	315,641	416,166	368,830	3,793	43,542
53											
54											
55 TRANSMISSION TOTALS	74,224,644	36,389,911	425,842	20,032,537	14,002,118	3,374,237	18,053,317	22,303,927	17,128,832	2,847,823	2,327,272
56											

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	2020	14,110,798	-	14,110,798	199,900	100	3,386,340	6,794,475
2	2021	453,000	-	14,563,798	204,000	1,000	3,634,340	7,038,475
3	2022	481,000	-	15,044,798	219,399	-	3,895,941	7,305,076
4	2023	749,741	-	15,794,539	222,680	-	4,423,002	7,832,137
5	2024	-	247,000	16,041,539	113,800	78,409	4,477,793	7,965,337
6	2025	-	247,000	16,288,539	114,000	74,988	4,535,805	8,098,337
7	2026	-	247,000	16,535,539	125,000	66,922	4,590,883	8,220,337
8	2027	-	247,000	16,782,539	108,000	99,227	4,630,656	8,359,337
9	2028	-	247,000	17,029,539	30,000	183,480	4,664,176	8,357,537
10	2029	-	247,000	17,276,539	88,739	206,127	4,616,310	8,515,798
11	2030	-	247,000	17,523,539	73,000	228,824	4,561,486	8,689,798
12	2031	-	247,000	17,770,539	63,000	247,830	4,497,655	8,873,798
13	2032	-	247,000	18,017,539	-	317,272	4,427,383	9,021,898
14	2033	-	247,000	18,264,539	49,000	269,901	4,355,483	9,179,898
15	2034	-	247,000	18,511,539	109,000	108,395	4,385,087	9,234,898
16	2035	-	247,000	18,758,539	27,000	164,263	4,440,825	9,309,898
17	2036	-	247,000	19,005,539	36,000	155,087	4,496,738	9,295,898
18	2037	-	247,000	19,252,539	112,940	108,712	4,522,086	9,422,958
19	2038	-	247,000	19,499,539	44,000	179,200	4,545,886	9,544,317
20	2039	-	247,000	19,746,539	84,000	136,583	4,572,303	9,632,317
21	2040	-	247,000	19,993,539	30,000	197,326	4,591,976	9,729,516
22	2041	-	247,000	20,240,539	-	229,554	4,609,423	9,781,516
23	2042	-	247,000	20,487,539	-	233,704	4,622,719	9,843,516
24	2043	-	247,000	20,734,539	-	210,212	4,659,507	9,856,516
25	2044	-	247,000	20,981,539	-	214,720	4,691,787	9,932,516
26	2045	-	247,000	21,228,539	-	226,975	4,711,812	9,987,516
27	2046	-	247,000	21,475,539	-	210,872	4,747,940	10,129,516
28	2047	-	247,000	21,722,539	-	242,417	4,752,523	10,222,516
29	2048	-	247,000	21,969,539	-	328,115	4,671,408	10,284,516
30	2049	-	247,000	22,216,539	-	331,482	4,586,926	10,417,716
31	2050	-	247,000	22,463,539	-	334,990	4,498,936	10,637,396
32	2051	-	247,000	22,710,539	-	338,643	4,407,293	10,703,396
33	2052	-	247,000	22,957,539	-	342,447	4,311,846	10,769,396
34	2053	-	247,000	23,204,539	-	346,409	4,212,437	10,818,035
35	2054	-	247,000	23,451,539	-	350,536	4,108,900	11,065,035
36	2055	-	247,000	23,698,539	-	354,835	4,001,066	11,312,035
37	2056	-	247,000	23,945,539	-	359,311	3,888,754	11,559,035
38	2057	-	247,000	24,192,539	-	363,974	3,771,780	11,806,035
39		\$15,794,539	\$8,398,000		\$2,053,458	\$7,842,843		

