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

## 2007 Supplemental Wholesale Power Rate Case
## Final Proposal

# FY 2009 REVENUE REQUIREMENT STUDY

September 2008

WP-07-FS-BPA-10

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## COMMONLY USED ACRONYMS

| | |
|---|---|
| AC | Alternating Current |
| AEP | American Electric Power Company, Inc. |
| AER | Actual Energy Regulation |
| AFUDC | Allowance for Funds Used During Construction |
| AGC | Automatic Generation Control |
| aMW | Average Megawatt |
| Alcoa | Alcoa Inc. |
| AMNR | Accumulated Modified Net Revenues |
| ANR | Accumulated Net Revenues |
| AOP | Assured Operating Plan |
| ASC | Average System Cost |
| Avista | Avista Corporation |
| BASC | BPA Average System Cost |
| BiOp | Biological Opinion |
| BPA | Bonneville Power Administration |
| Btu | British thermal unit |
| C&R Discount | Conservation and Renewables Discount |
| CAISO | California Independent System Operator |
| CBFWA | Columbia Basin Fish & Wildlife Authority |
| CCCT | Combined-Cycle Combustion Turbine |
| CEC | California Energy Commission |
| CFAC | Columbia Falls Aluminum Company |
| Cfs | Cubic feet per second |
| CGS | Columbia Generating Station |
| COB | California-Oregon Border |
| COE | U.S. Army Corps of Engineers |
| Con Aug | Conservation Augmentation |
| C/M | Consumers / Mile of Line for Low Density Discount |
| ConMod | Conservation Modernization Program |
| COSA | Cost of Service Analysis |
| Council | Northwest Power Planning and Conservation Council |
| CP | Coincidental Peak |
| CRAC | Cost Recovery Adjustment Clause |
| CRC | Conservation Rate Credit |
| CRFM | Columbia River Fish Mitigation |
| CRITFC | Columbia River Inter-Tribal Fish Commission |
| CT | Combustion Turbine |
| CY | Calendar Year (Jan-Dec) |
| DC | Direct Current |
| DDC | Dividend Distribution Clause |
| DJ | Dow Jones |
| DOE | Department of Energy |
| DOP | Debt Optimization Program |

| | |
|---|---|
| DROD | Draft Record of Decision |
| DSI | Direct Service Industrial Customer or Direct Service Industry |
| ECC | Energy Content Curve |
| EIA | Energy Information Administration |
| EIS | Environmental Impact Statement |
| EN | Energy Northwest, Inc. |
| Energy Northwest, Inc. | Formerly Washington Public Power Supply System (Nuclear) |
| EPA | Environmental Protection Agency |
| EPP | Environmentally Preferred Power |
| EQR | Electric Quarterly Report |
| ESA | Endangered Species Act |
| EWEB | Eugene Water & Electric Board |
| F&O | Financial and Operating Reports |
| FB CRAC | Financial-Based Cost Recovery Adjustment Clause |
| FBS | Federal Base System |
| FCCF | Fish Cost Contingency Fund |
| FCRPS | Federal Columbia River Power System |
| FCRTS | Federal Columbia River Transmission System |
| FERC | Federal Energy Regulatory Commission |
| FERC SR | Federal Energy Regulatory Commission Special Rule |
| FELCC | Firm Energy Load Carrying Capability |
| Fifth Power Plan | Council's Fifth Northwest Conservation and Electric Power Plan |
| FPA | Federal Power Act |
| FPS | Firm Power Products and Services (rate) |
| FY | Fiscal Year (Oct-Sep) |
| GAAP | Generally Accepted Accounting Principles |
| GCPs | General Contract Provisions |
| GEP | Green Energy Premium |
| GI | Generation Integration |
| GSR | Generation Supplied Reactive and Voltage Control |
| GRI | Gas Research Institute |
| GRSPs | General Rate Schedule Provisions |
| GSP | Generation System Peak |
| GSU | Generator Step-Up Transformers |
| GTA | General Transfer Agreement |
| GWh | Gigawatthour |
| HLH | Heavy Load Hour |
| HOSS | Hourly Operating and Scheduling Simulator |
| ICNU | Industrial Customers of Northwest Utilities |
| ICUA | Idaho Consumer-Owned Utilities Association, Inc. |
| IOU | Investor-Owned Utility |
| IP | Industrial Firm Power (rate) |
| IP TAC | Industrial Firm Power Targeted Adjustment Charge |
| IPC | Idaho Power Company |

| | |
|---|---|
| ISO | Independent System Operator |
| JP | Joint Party |
| JP1 | Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities |
| JP2 | Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor) |
| JP3 | Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor) |
| JP4 | Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2 |
| JP5 | Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1] |
| JP6 | Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc. |
| JP7 | NONE |
| JP8 | Northwest Energy Coalition, Save Our *Wild* Salmon |
| JP9 | Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, |

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis, and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

| | |
|---|---|
| | Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company |
| JP10 | Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities |
| JP11 | Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma |
| JP12 | Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members |
| JP13 | Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe |
| JP14 | Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members |
| JP15 | Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC |
| kAf | Thousand Acre Feet |
| kcfs | kilo (thousands) of cubic feet per second |
| ksfd | thousand second foot day |
| kV | Kilovolt (1000 volts) |
| kW | Kilowatt (1000 watts) |
| kWh | Kilowatt-hour |
| LB CRAC | Load-Based Cost Recovery Adjustment Clause |
| LCP | Least-Cost Plan |
| LDD | Low Density Discount |
| LLH | Light Load Hour |
| LOLP | Loss of Load Probability |
| m/kWh | Mills per kilowatt-hour |
| MAC | Market Access Coalition Group |
| MAf | Million Acre Feet |
| MCA | Marginal Cost Analysis |
| Mid-C | Mid-Columbia |
| MIP | Minimum Irrigation Pool |

| | |
|---|---|
| MMBTU/MMBtu | Million British Thermal Units |
| MNR | Modified Net Revenues |
| MOA | Memorandum of Agreement |
| MOP | Minimum Operating Pool |
| MORC | Minimum Operating Reliability Criteria |
| MT | Market Transmission (rate) |
| MVAr | Mega Volt Ampere Reactive |
| MW | Megawatt (1 million watts) |
| MWh | Megawatt-hour |
| NCD | Non-coincidental Demand |
| NWEC | Northwest Energy Coalition |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Council |
| NF | Nonfirm Energy (rate) |
| NFB Adjustment | National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment |
| 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 |
| Northwest Power Act | Pacific Northwest Electric Power Planning and Conservation Act |
| NPA | Northwest Power Act |
| NPCC | Northwest Power and Conservation Council |
| NPV | Net Present Value |
| NR | New Resource |
| NR (rate) | New Resource Firm Power (rate) |
| NRU | Northwest Requirements Utilities |
| NTSA | Non-Treaty Storage Agreement |
| NUG | Non-Utility Generation |
| NWPP | Northwest Power Pool |
| NWPPC | Northwest Power Planning Council |
| OATT | Open Access Transmission Tariff |
| O&M | Operation and Maintenance |
| OMB | Office of Management and Budget |
| OPUC | Oregon Public Utility Commission |
| ORC | Operating Reserves Credit |
| OY | Operating Year (Aug-Jul) |
| PA | Public Agency |
| PacifiCorp | PacifiCorp |
| PS | Power Services |
| PDP | Proportional Draft Points |

| | |
|---|---|
| PF | Priority Firm Power (rate) |
| PFR | Power Function Review |
| PGE | Portland General Electric Company |
| PGP | Public Generating Pool |
| PMA | Power Marketing Agencies |
| PNCA | Pacific Northwest Coordination Agreement |
| PNGC | Pacific Northwest Generating Cooperative |
| PNRR | Planned Net Revenues for Risk |
| PNW | Pacific Northwest |
| POD | Point of Delivery |
| POI | Point of Integration/Point of Interconnection |
| POM | Point of Metering |
| PPC | Public Power Council |
| PPLM | PP&L Montana, LLC |
| Project Act | Bonneville Project Act |
| PSA | Power Sales Agreement |
| PSC | Power Sales Contract |
| PSE | Puget Sound Energy |
| PSW | Pacific Southwest |
| PTP | Point-to-Point Transmission |
| PUD | Public or People's Utility District |
| RAM | Rate Analysis Model (computer model) |
| RAS | Remedial Action Scheme |
| Reclamation | Bureau of Reclamation |
| Renewable Northwest | Renewable Northwest Project |
| RD | Regional Dialogue |
| REP | Residential Exchange Program |
| RFP | Request for Proposal |
| RiskMod | Risk Analysis Model (computer model) |
| RiskSim | Risk Simulation Model |
| RL | Residential Load (rate) |
| RMS | Remote Metering System |
| ROD | Record of Decision |
| RPSA | Residential Purchase and Sale Agreement |
| RTO | Regional Transmission Operator |
| SCCT | Single-Cycle Combustion Turbine |
| Slice | Slice of the System (product) |
| SME | Subject Matter Expert |
| SN CRAC | Safety-Net Cost Recovery Adjustment Clause |
| SOS | Save Our *Wild* Salmon |
| SUB | Springfield Utility Board |
| SUMY | Stepped-Up Multiyear |
| SWPA | Southwestern Power Administration |
| TAC | Targeted Adjustment Charge |
| TBL | Transmission Business Line |

| | |
|---|---|
| Tcf | Trillion Cubic Feet |
| TPP | Treasury Payment Probability |
| Transmission System Act | Federal Columbia River Transmission System Act |
| TRL | Total Retail Load |
| Tribes | Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively |
| UAI Charge | Unauthorized Increase Charge |
| UAMPS | Utah Associated Municipal Power Systems |
| UDC | Utility Distribution Company |
| UP&L | Utah Power & Light |
| URC | Upper Rule Curve |
| USBR | U.S. Bureau of Reclamation |
| USFWS | U.S. Fish and Wildlife Service |
| VOR | Value of Reserves |
| WAPA | Western Area Power Administration |
| WECC | Western Electricity Coordinating Council (formally called WSCC) |
| WMG&T | Western Montana Electric Generating and Transmission Cooperative |
| WPAG | Western Public Agencies Group |
| WPRDS | Wholesale Power Rate Development Study |
| WSCC | Western Systems Coordination Council (now WECC) |
| WSPP | Western Systems Power Pool |
| WUTC | Washington Utilities and Transportation Commission |
| Yakama | Confederated Tribes and Bands of the Yakama Nation |

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# 1. INTRODUCTION

## 1.1 Purpose and Development of the Revenue Requirement Study for Generation

The purpose of this Study is to establish the revenues from wholesale power rates necessary to recover, in accordance with sound business principles, the Federal Columbia River Power System (FCRPS) costs associated with the production, acquisition, marketing, and conservation of electric power. The generation revenue requirement includes: recovery of the Federal investment in hydro generation, fish and wildlife, and conservation costs; Federal agencies' operations and maintenance (O&M) expenses allocated to power; capitalized contract expenses associated with non-Federal power suppliers such as Energy Northwest (EN); other power purchase expenses, such as short-term power purchases; power marketing expenses; cost of transmission services necessary for the sale and delivery of FCRPS power; and all other generation-related costs incurred by the Administrator pursuant to law.

The cost evaluation period, as defined by the Federal Energy Regulatory Commission (FERC), is the period extending from the last year for which historical information is available, through the proposed rate approval period. The cost evaluation period for this rate filing includes Fiscal Years (FY) 2008-2009. One of the purposes of this proceeding is to recalculate power rates for FY 2009. As such, the proposed rate approval period is only FY 2009. This Study is based on a generation revenue requirement for that year and incorporates the repayment schedule from generation repayment studies that had been filed as part of the 2007 Wholesale Power Rate Adjustment Proceeding. This Study does ***not*** include revenue requirements or a cost recovery demonstration for the Bonneville Power Administration's (BPA) transmission function.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine revenue requirements. Chapter 5 of this Study summarizes the legal requirements. Volumes 1 and 2 of Revenue Requirement Study Documentation, WP-07-FS-BPA-10A and WP-07-FS-BPA-10B, respectively, contain key technical assumptions and calculations, the results of the generation repayment studies, and a further explanation of the repayment program and its outputs.

The revenue requirement for this study was developed using a cost accounting analysis comprised of three parts. First, a repayment study for the generation function was prepared that incorporated the FY 2009 amortization payment from the WP-07 filing with FERC. The repayment study also developed an amortization schedule for the 50-year repayment period and projected annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and related generation assets. Second, generation operating expenses were incorporated and cash flows were evaluated to determine that Minimum Required Net Revenues were not necessary. Third, risk requirements, BPA's cost recovery goals, and other risk mitigation measures were evaluated, and it was determined that Planned Net Revenues for Risk (PNRR) also were not necessary. (*See* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12, Section 3.5.3.2) From these three steps, the revenue requirement is set at the revenue level necessary to fulfill cost recovery requirements and objectives through the process depicted in Figure 1, Generation Revenue Requirement Process, of this chapter.

Consistent with Department of Energy (DOE) policy RA 6120.2, described in Chapter 5 of this Study, and the standards applied by FERC on review of BPA's rates, the adequacy of both current and proposed rates must be demonstrated. BPA conducts a current revenue test to determine whether revenues projected from current rates meet cost recovery requirements. If the current revenue test indicates that cost recovery and risk mitigation requirements are met, current rates could be extended. The current revenue test, described in Chapter 4.2 of this Study, demonstrates that revenues from current rates will recover generation costs. Despite this result, BPA is revising its rates for FY 2009 in light of the Ninth Circuit's invalidation of 2000 Residential Exchange Program Settlement Agreements. The revised revenue test determines whether projected revenues from proposed rates meet cost recovery requirements and objectives for the rate test and repayment periods. The revised revenue test, contained in Chapter 4.3 of this Study, demonstrates that revenues from the proposed wholesale power rates recover generation costs in the rate test period as well as over the ensuing 50-year repayment period. Rate test period costs are projected to be recovered with a very high confidence level, meeting BPA's 97.5 percent probability standard that all United States (U.S.) Treasury payments in the generation function will be recovered on time and in full through wholesale power rates for a one-year period. (*See* FY 2009 Risk Analysis Study, WP-07-FS-BPA-12.)

Table 1 summarizes the revised revenue test and shows projected net revenues from proposed rates for FY 2009. These net revenues are the lowest level necessary to achieve BPA's cost recovery objectives, when combined with other risk mitigation tools, given hydro condition uncertainty, market price volatility, and other risks.

**Table 1**

**Projected Net Revenues from Projected Rates for FY 2009**

($000s)

| | |
|---|---|
| Projected Revenues from Proposed Rates | $2,737,298 |
| Projected Expenses | 2,734,006 |
| Net Revenues | $3,292 |

Table 2 shows the planned generation amortization payments to the U.S. Treasury that were calculated for the original FY 2007-2009 rate period as well as irrigation assistance payments that are due to be paid from power revenues. To demonstrate cost recovery by year in the rate period, it was necessary in the WP-07 Final Proposal to shift $82 million in planned amortization from FY 2009 to FY 2007 and 2008 because revenues in FY 2009 were insufficient to cover all cash requirements in that year. Consequently, planned amortization was reshaped, without changing the total amount planned for the rate period, to accommodate the shape of the forecast revenues. This reshaping has been a longstanding practice in BPA rate filings to ensure adequate cash flows from proposed rates to meet annual cash requirements. (*See for example* 2006 Initial Transmission Proposal Revenue Requirement Study, TR-06-E-BPA-01.) As stated above, the amortization scheduled in the WP-07 Final Proposal has been incorporated in this Supplemental Rate Proceeding. The scheduled amortization for FY 2009 has been applied to the development of the base revenue requirement income statement (Table 5A) and statement of cash flows (Table 5A). (*See* Homenick, *et al.*, WP-07-E-BPA-65, at 4.)

**Table 2**
**Planned Federal Amortization & Irrigation Assistance Payments**
($000s)

| Annual Fiscal Year | Amortization | Irrigation Assistance |
|---|---|---|
| 2008 | $277,781 | $2,950 |
| 2009 | $103,065 | $7,279 |
| Total | $380,846 | $10,229 |

## 1.2 Debt Optimization Program

After base power rates were filed for the FY 2002-2006 rate period, BPA instituted a Debt Optimization Program (DO) with EN as a means of replenishing Treasury borrowing authority. DO involves extending EN debt that has come due and using the cash flows that would have gone to pay the EN debt to repay an equivalent amount of Federal debt. The program has resulted in a considerable amount of Federal debt, primarily bonds issued to Treasury, but also some Congressional appropriations, being paid well in advance of the amortization schedules established in the WP-02 rate filing. As the program continues, this will create additional advance amortization, compared to the schedules that would have been established without DO, for the subsequent rate periods through 2012. Effectively, the extension of EN debt into the FY 2013-2018 period has pushed forward the repayment of Federal debt relative to the amount that otherwise would have been scheduled to be paid in that period. BPA has committed to EN that it would follow this program, matching dollar -for -dollar the repayment of Federal obligations in the same year in which EN debt has been extended, absent dire financial circumstances that might cause some delay in the payment of the advanced portion of the amortization.

Although DO may continue in FY-2009, only EN debt refinancing transactions completed through FY 2008 are incorporated in the development of this rate proposal. However, in establishing amortization schedules for FY 2009, EN bonds that were refinanced in FY 2001-2002 more that 90 -days in advance of their due dates, known as advanced refundings, are taken into account in preparing repayment studies in order to fulfill the commitment for the dollar-for-dollar repayment of Federal obligations. (*See* Homenick, *et al.*, WP-07-E-BPA-10, at 8.) The total planned annual amortization was derived through a two-phase repayment study procedure. A base level of amortization was established for each year of the rate period as though EN advanced refundings had not occurred. The additional amortization equivalent to the

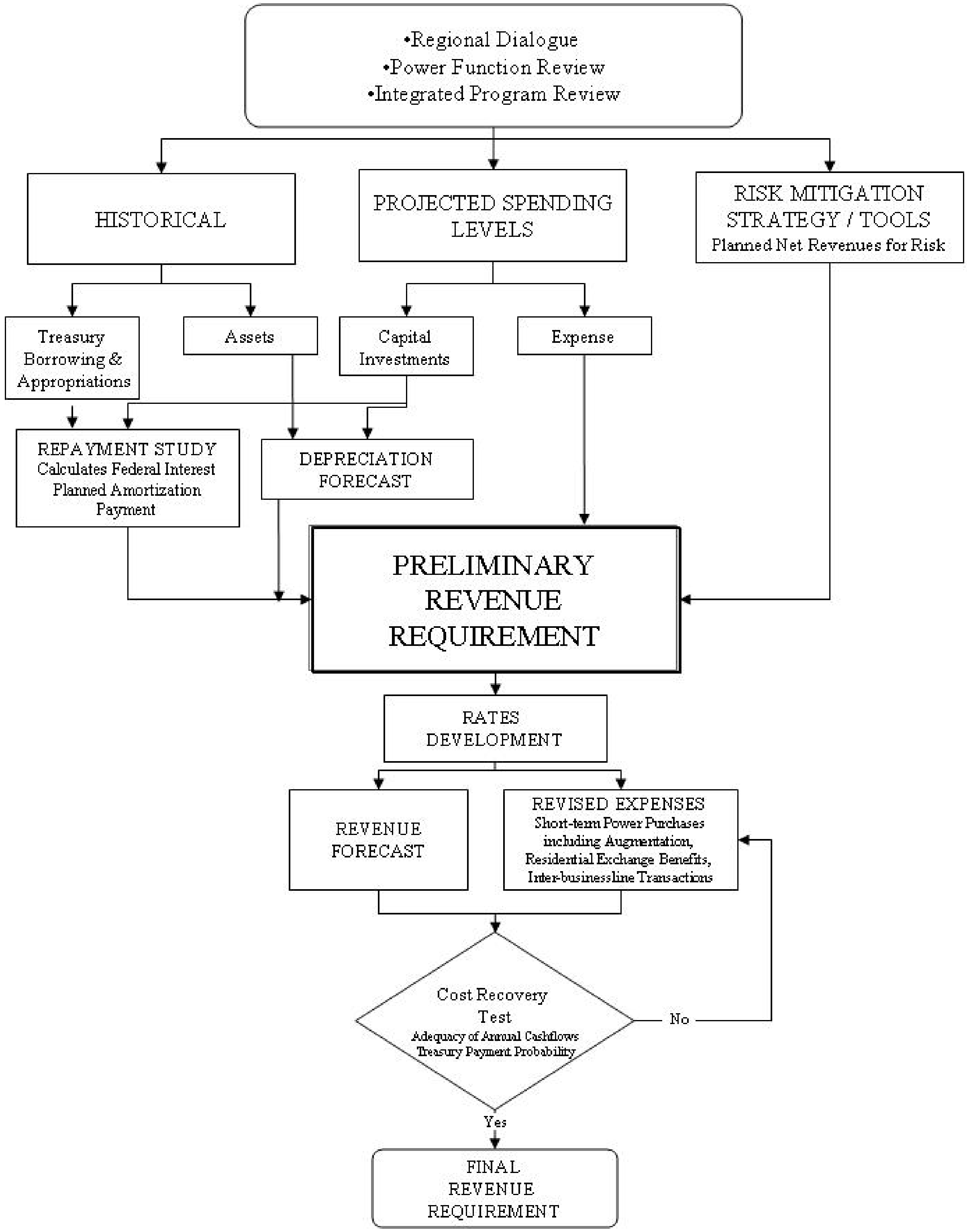
EN principal advance refinanced in each year was then added to the base schedule. (*Id.* at 8-9). Table 3 shows the composition of the resulting planned annual amortization payments established in the WP-07 Final Proposal, to which this Final Supplemental Proposal will adhere. Table 3 also displays an additional $37.4 million payment in FY 2008 that is part of the Debt Optimization program.

**Table 3**
**Composition of Annual Amortization Payments**
($000s)

| Fiscal Year | Base Amortization | Advanced Amortization | Debt Optimization | Total Amortization |
|---|---|---|---|---|
| 2008 | $176,983 | $ 63,500 | $37,388 | $277,781 |
| 2009 | $ 24,965 | $ 78,100 | | $103,065 |
| Total | $201,948 | $141,600 | $37,388 | $380,846 |

**FIGURE 1**

**GENERATION REVENUE REQUIREMENT PROCESS**



### 1.3 Public Involvement Process

BPA participated in two major public processes that had, and will continue to have, significant impacts on its methods and costs of doing business: the Regional Dialogue and the program spending review process, originally known as the Power Function Review (PFR) and now known as the Integrated Program Review (IPR). In 2004, BPA began the Regional Dialogue, a two-phase public process, to outline how it will market Federal power and distribute the costs and benefits of the FCRPS. The first phase focused on issues to be addressed prior to the beginning of 2007 Wholesale Power Rate Adjustment Proceeding Case. The second phase is on-going and focuses on long-term issues that must be resolved prior to the end of current Subscription contracts in 2011.

The PFR, which also had two phases, had the objective of ensuring that BPA's generation costs are as low as possible, consistent with sound business practices, thereby facilitating full cost recovery with power rates at or below market prices. The PFR established program spending forecasts that were used in the WP-07 Initial and Final Proposals. The IPR produced updated program spending forecasts for use in the WP-07 Supplemental Wholesale Rate Adjustment Proceeding. Chapter 2 describes the chronology of the spending level development process. The recommendations from the IPR form the basis of these revenue requirements. (*See* Study, WP-07-FS-BPA-10, Appendix A.)

## 2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

### 2.1 Process for the 2007 Wholesale Power Rate Adjustment Proceeding

The development of program levels for FY 2007-2009 used in the WP-07 rate case began early in the FY 2002-2006 rate period. BPA began to impose more stringent cost controls and spending reductions in FY 2002 in response to the financial effects of the West Coast energy crisis and continued with several processes in FYs 2003 and- 2004 to identify ways to address an expected shortfall in net revenues. BPA and its stakeholders successfully identified ways to reduce expenses and enhance revenues.

The development of the specific program spending levels in this proposal occurred primarily in the IPR and the PFR.

#### 2.1.1 Regional Dialogue

The Regional Dialogue process evolved out of an effort jointly -sponsored by BPA and the NWPCC, initiated in 2002, to outline how BPA should market the power generated by the FCRPS. The first phase, known as the Near-Term Regional Dialogue, addressed issues needing immediate resolution for the post-2006 rate period and culminated in a policy and Record of Decision (ROD) for power service in FY 2007-2011 (Near-Term Policy and ROD) issued in February 2005.[2]

Some of the conclusions of the Regional Dialogue had a direct impact on financial issues relevant to the FY 2007-2009 rate period. In particular, the Regional Dialogue recommended that BPA should cap its net expense for facilitating renewable resource development at

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[2] See the BPA web site at www.bpa.gov/power/pl/regionaldialogue/02-2005_rod.pdf for a copy of the Near-Term Regional Dialogue Record of Decision.

$21 million per year. It also recommended that BPA should provide service to DSIs at a known quantity and capped cost of $59 million per year, which would be determined in a separate DSI ROD.[3] This decision was reaffirmed and further defined in a 2006 supplement to the 2005 DSI ROD.[4]

In the Near-Term ROD, BPA also said that it would continue to focus on promoting financial transparency, allow for public input on agency costs, and demonstrate management of those costs, including engaging customers in the PFR to discuss power spending levels that will be used to set power rates for the FY 2007-2009 rate period.

### 2.1.2 Power Function Review

BPA began the PFR in January 2005 with the first in a series of technical, management, and public workshops. The PFR was designed to provide an opportunity for customers and constituents to examine, understand, and provide input on BPA's cost projections that form the basis for the WP-07 wholesale power rate case. A total of 19 workshops were held to discuss the projected spending levels of the Columbia Generating Station (CGS), Corps of Engineers (COE), Bureau of Reclamation, conservation program, renewables program, fish and wildlife program, Power Services (PS) internal operations, transmission purchases and ancillary services program, BPA corporate costs, Federal and non-Federal debt management, as well as the complexities of risk mitigation. Where appropriate, Regional Dialogue policy decisions were incorporated in the PFR spending level projections.

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[3] See the BPA web site at www.bpa.gov/power/pl/regionaldialogue/06-2005_dsi_rod.pdf for a copy of the Record of Decision.
[4] See the BPA web site at www.bpa.gov/power/pl/regionaldialogue/05-31-2006_dsi_rod_supplement.pdf for a copy of the Supplemental DSI ROD.

Based on comments received during the PFR process, BPA changed some of its forecasts of program costs spending levels for the WP-07 Initial Proposal. In addition to changes in spending levels, BPA committed to conducting an additional public process to review program spending levels that would be concurrent with this rate proceeding so that any reductions in spending levels could be incorporated in the WP-07 Final Proposal. This commitment led to the second phase of the PFR known as PFR II, which began after the publication of the Initial Proposal. BPA held a series of public workshops in early 2006 focused on each of the major power expense categories which were reviewed previously in the first phase of the PFR. While this was primarily an effort to update cost assumptions and identify additional reductions, this process also provided a forum to review other non-cost issues that could affect power rates, such as BPA's ongoing efforts to develop liquidity tools.

The WP-07 Final Proposal Revenue Requirement Study, WP-07-FS-BPA-2, Chapter 2, describes in greater detail the outcomes of the PFR and PFR II processes. Appendix 1 of that document contains the close-out reports of these processes.

### 2.1.3 Development Process for the FY 2009 Revenue Requirement

To ensure that the development of the initial WP-07 Supplemental Proposal reflected current forecasts of program spending levels, BPA reviewed its expense forecasts and updated several program spending categories to reflect more recent forecasts for FY 2009. BPA also committed to holding a public process, the IPR, outside of this rate proceeding to review changes to spending forecasts for FY 2009 for use in the final Supplemental Proposal. The operations and maintenance expense forecast for the Columbia Generating Station (CGS) was revised upward by $31.5 million to reflect more recent estimates of future requirements. The Long-Term Contract Generating Resource Projects expense forecast was increased by $6 million to account for the power purchase expense associated with the acquisition of the output of the Idaho Falls bulb turbine project. Similarly, forecasted Renewables costs have been increased by $11.5 million to account for (i) a new contract to purchase a portion of the output of the Klondike III wind project, and (ii) increased projected spending levels for renewable resource facilitation and research and development activities made possible by higher projected Green Tag revenues. The expense forecast for Energy Efficiency projects was increased by $9 million. However, this is a reimbursable program so there is a corresponding increase in the forecast of miscellaneous revenues. Augmentation costs were increased to account for the cost of serving higher FY 2009 loads, but the IOU deferred augmentation expense, which falls under the umbrella of the Residential Exchange Program Settlement Agreements stuck down by the U.S. Court of Appeals for the Ninth Circuit, was removed. The net increase in the forecast of augmentation costs is $13 million. Other Power Purchases (short term balancing purchases) also increased slightly to account for updates to loads, resources, and market prices. Depreciation, amortization, and debt service costs have been updated in this Study to reflect historical results for FY 2006 and FY 2007 which were forecast periods in the Final Proposal. The forecast for DSI Monetized Power Sales was reduced by $4 million based on changes in how the DSI contracts are being implemented. (*See* Risk Analysis Study, WP-07-E-BPA-48, Section 2.4.7.) Finally, the Residential Exchange/IOU Settlement Benefits category has been modified to reflect only the Residential Exchange benefits calculated in this supplemental proceeding.

BPA conducted the IPR process in May and June 2008 in order to ensure the final Supplemental Proposal incorporated BPA's most current forecasts of program spending levels for FY 2009 and that there was an opportunity for public review and comment on those spending levels. The IPR consisted of four days of public workshops in May and a general manager-level meeting in June. A public comment period ran from May 15, 2008 to June 19, 2008. After carefully considering the comments in the IPR, BPA made adjustments that produced an approximately $8 million reduction from the initial IPR forecast. The largest reductions were in internal and conservation program levels and conservation capital forecasts for fiscal year 2009. The close-out letter for the IPR is included in this document as Appendix A. (*See* Supplemental Revenue Requirement Study, WP-07-FS-BPA-10, Appendix A.)

The final IPR close-out report for FY 2009 reflects a 1.2 percent increase in total program spending when compared to the forecast of FY 2009 program spending levels used in the WP-07 Final Proposal. The close-out report forecasted annual program spending of $2,737 million. The changes made during the IPR include an increase of $50.8 million for Columbia Generating Station Operations and Maintenance costs to improve plant reliability, a $13.4 million increase in Corps of Engineers and Bureau of Reclamation Operations and Maintenance, an increase of $5.8 million in the Long-term Generation Program, a $14 million increase in Conservation, a $13 million increase in Internal Operations, and a $56 million increase in projected Fish and Wildlife spending. These increases in program spending levels are largely offset by an expected reduction of over $100 million in the cost of the Residential Exchange program and a $24 million decrease in capital-related expenses (net interest, non-Federal debt service, and depreciation and amortization.

Subsequent to the end of the IPR, BPA changed two spending categories. The forecast of Transmission expenses was reduced by $975,000 to reflect the final rate case forecast of power purchases. The forecast of EN debt service was changed to incorporate an unexpected reduction in FY 2009 of $500,000 to reflect an updated forecast of treasury service fees.

## 2.2 Capital Funding

The forecast of FCRPS capital investments for FY 2008-2009 was updated in the IPR for the 2007 Supplemental Final Proposal. The following section reflects forecasts developed in the IPR. FCRPS capital investments include COE, BOR, and BPA capital investments as well as third-party resource investments for which debt is secured by BPA (capitalized contracts). Projections of current FCRPS capital outlays are $732 million for the cost evaluation period. These investments include:

- efficiency and reliability improvements and replacements in hydro generation;
- investment in fish and wildlife recovery funded by BPA and by appropriations and implemented by various groups in the Northwest, including the COE and Reclamation. Fish and wildlife investment includes tributary passage, hatchery facility construction, gas abatement, mainstem passage, and land acquisition, provided such costs exceed $1 million and such investment provides a creditable/quantifiable benefit against a defined obligation for BPA;
- investment in capital equipment;
- investment in conservation activities; and
- capital investments at EN's CGS.

The sources of capital for FY 2008-2009 investments are summarized below.

| | |
|---|---|
| Bonds Issued to U.S. Treasury | ($ in millions) |
| Direct Funding | $283 |
| BPA (Capital Equipment) | 33 |
| BPA Fish and Wildlife | 75 |
| Conservation | 47 |
| Sub-Total | 438 |
| Federal Appropriations* | 294 |
| Non-Federal | 102 |
| Total | $834 |

* Reflects projected plant-in-service, not Congressional appropriations for the period.

Table 4, which follows this chapter, provides a detailed breakout of investment projections for FY 2009 only. This Study projects that no capital investments will be funded from current revenues.

### 2.2.1 Bonds Issued to the U.S. Treasury

Bonds issued to the U.S. Treasury are the source of capital that will be used to finance FY 2008-2009 BPA capital program investments and COE and Reclamation investments that BPA has agreed to direct-fund under P.L. No. 102-486. These expenditures include a projection of $363 million split among BPA fish and wildlife direct program investments, conservation investments ($47 million), BPA capital equipment ($33 million), and generating resource investments of the COE and Reclamation ($283 million) during FY 2008-2009.

Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in Chapter 6 of the Documentation, WP-07-FS-BPA-10A.

### 2.2.2 Federal Appropriations

The revenue requirement study, in general, reflects that all COE and Reclamation capital investments of the FCRPS will be financed by Federal appropriations unless they are direct-funded by BPA. In this Study, such appropriated investments are projected to total $294 million in COE investments for fish and wildlife recovery during the rate period. No other appropriations-financed investments are forecast for the rate period. Capital investments funded by this source do not become BPA's obligation until placed in service.

The interest rate forecast for appropriated capital investments expected to be placed in service is found in Chapter 6 of the Documentation, WP-07-FS-BPA-10A. Each new capital investment is assigned a rate from the U.S. Treasury yield curve prevailing in the month prior to the beginning of the fiscal year in which the new investment is placed in service.

To determine interest during construction for new capital investments, the prevailing U.S. Treasury one-year rate for each fiscal year of construction is applied to the sum of the cumulative expenditures made and interest during construction that has accrued prior to the end of the subject fiscal year. (*See* Study, WP-07-FS-BPA-10, Chapter 5 and Revenue Requirement Study Documentation, WP-96-FS-BPA-02A, Chapter 9.)

### 2.2.3 Third-Party Debt

Third-party debt differs from U.S. Treasury debt in that entities other than BPA or U.S. Treasury issue the debt. BPA's promise to make payments serves as security for bonds or other debt that the third-party issues, resulting in wider market access and potentially more favorable interest rates for the seller. Examples of acquisitions financed in this way include EN's WNP-1, WNP-3 and CGS nuclear power projects and the Lewis County Public Utility District Hydroelectric project (Cowlitz Falls). This Study includes debt service on $101.9 million in total projected CGS capital investments by EN to be financed by issuing bonds in FY 2009. Each new capital investment is assigned an interest rate from the tax exempt municipal bond yield curve corresponding with the term of the bond. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 6.)

**Table 4**

**FEDERAL COLUMBIA RIVER POWER SYSTEM (FCRPS)**
**PROJECTED CAPITAL FUNDING REQUIREMENTS FOR THE POWER BUSINESS LINE**
**2009 SUPPLEMENTAL RATE PROPOSAL**
($ in Millions)

| | Rate Period |
|---|---|
| | FY 2009 |
| **POWER** | |
| **Capital Requirements for Revenue Producing Investments** | |
| Corps & Bureau Additions/Replacements - Direct Funded | 133.2 |
| Corps & Bureau Additions/Replacements - Appropriations | 0.0 |
| PBL Capital Equipment | 12.7 |
| Capitalized Bond Premium | 0.0 |
| CGS: Additions/Replacements | 101.9 |
| CGS: Fuel | 0.0 |
| Other Non - Federal | 0.0 |
| **Annual Capital Requirements for Revenue Producing Investments** | **247.8** |
| **Capital Requirements for Non-Revenue Producing and Public Benefit Investments** | |
| **Energy Conservation** | 27.2 |
| **Fish Investment** | |
| BPA Fish and Wildlife Investment | 50.0 |
| Corps & Bureau Fish Investment - Appropriations | 110.0 |
| **Total Fish Investment** | 160.0 |
| Other Third - Party | 0.0 |
| **Annual Capital Req. for Non-Rev. & Public Benefit Invests.** | **187.2** |
| **ANNUAL FUNDING REQUIREMENTS FOR POWER** | **435.0** |

## 3. DEVELOPMENT OF REVENUE REQUIREMENTS

Typically, repayment studies are performed as the first step in determining revenue requirements. The studies establish the schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments.

The horizon of each repayment study is 50 years after each rate test year. In conducting the repayment studies, BPA includes debt service payments associated with its capitalized contract obligations; fixed payments associated with long-term energy resource acquisition contracts; and outstanding and projected generation repayment obligations on appropriations (including irrigation assistance) and on bonds issued to the U.S. Treasury.

Funding for replacements projected during the repayment period are also included in the repayment study, consistent with the requirements of RA 6120.2. COE and BOR replacements funded by appropriations and placed in service in 1994 or later have repayment periods that are set at the weighted average service life of all replacements going into service at that project in that year. Appropriations are scheduled to be repaid within the expected useful life of the associated facility, or 50 years, whichever is less.

Bonds issued by BPA to the U.S. Treasury may include three-year to 45-year terms, taking into account the estimated average service lives for investments and prudent financing and cash management factors. Some bonds are issued with a provision that allows the bond to be called after a certain time, typically five years. Bonds may also be issued with no early call provision. Early retirement of eligible bonds requires that BPA pay a bond premium to the U.S. Treasury. In addition, the interest rate that BPA pays on callable bonds is higher than the interest rate on non-callable bonds issued at the same time.

Bonds are issued to finance BPA conservation acquisition, the fish and wildlife program, and COE and Reclamation investments direct-funded by BPA, and are repaid within the terms and conditions of each bond issued to the U.S. Treasury. Bonds to finance fish and wildlife capital investments are issued with maturities not to exceed 15 years, the same period over which BPA amortizes these capital investments. COE and Reclamation direct-funding bonds are issued with maturities not to exceed 45 years. Conservation bonds are issued with maturities that are consistent with the period over which BPA amortizes these capital investments. Currently, BPA has three amortization schedules for conservation assets. Investments made prior to FY 2002, referred to as the Conservation Legacy program, have a straight-line, 20-year amortization period. Investments made from FY 2002 through FY 2006, known as Conservation Augmentation investments, have a declining 10-year amortization period to be completed by 2011. Investments made beginning in FY 2007, known as Conservation Acquisition investments, will have a straight-line five-year amortization period. (*See* Administrator's Record of Decision, WP-07-A-02, Chapter 4.4.)

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 generation obligations within the required repayment period. As stated previously, the repayment study for this supplemental rate proposal incorporates the FY 2009 amortization payment established in the WP-07 Final Proposal filed with FERC.

Further discussion of the repayment program and tables is included in Appendix B of the Revenue Requirement Study, WP-07-FS-BPA-10, and in Chapter 9 of Documentation, WP-07-FS-BPA-10B. (*See* Chapter 5 of this Study for an explanation of repayment policies and requirements.)

# 4. FY 2009 GENERATION REVENUE REQUIREMENT

## 4.1 Revenue Requirement Format

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

The Income Statement (Table 5A) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 16), Net Interest Expense (Line 25), Minimum Required Net Revenues (Line 27), and PNRR (Line 28). The sum of these four major components is the Total Revenue Requirement (Line 30).

The amounts shown in Total Operating Expenses and Net Interest Expense are primarily established outside the rate setting process. The Minimum Required Net Revenues (Line 27) result from an analysis of the Statement of Cash-Flow (Table 5B). Minimum Required Net Revenues 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 power repayment studies and any other cash requirements, such as payment of irrigation assistance.

The Statement of Cash-Flow analyzes annual cash inflows and outflows. Cash provided by Current Operations (Line 8), driven by the Non-Cash items shown in Lines 4, 5, 6, and 7, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 14) and Cash from Treasury Borrowing and Appropriations (Line 21). If cash provided by

Current Operations is not sufficient, Minimum Required Net Revenues must be included in revenue requirements to accommodate the shortfall, yielding at least zero annual Increase in Cash (Line 22). The Minimum Required Net Revenues amount shown on the Statement of Cash Flows (Line 2) is then incorporated in the Income Statement (Line 27).

### 4.1.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 5A). Volume 1 of Revenue Requirement Study Documentation, WP-07-FS-BPA-10A, provides additional information on the development and use of the data contained in the tables.

**Power System Generation Resources (Line 2).** This category encompasses the costs associated with power generated by Federal hydroelectric facilities operated by the COE and BOR and power obtained through contracts for non-Federal resources. This category includes lines 3 through 8, described below.

**Operating Generation Resources (Line 3).** This category includes the operations and maintenance expenses associated with power-producing resources including the CGS, BOR, COE, and the annual expenses associated with long-term contract generating projects.

**Operating Generation Settlement Payments (Line 4).** A settlement agreement between the Confederated Tribes of the Colville Reservation and the United States was signed in 2004 concerning the construction of Grand Coulee Dam. The Settlement Act (Public Law 103-436) ratifying the settlement agreement authorizes BPA to make annual payments to the Tribes for the use of tribal lands for power production at the Columbia Basin project.

**Non-Operating Generation (Line 5).** This category includes the decommissioning costs of the Trojan nuclear plant and the unfinished WNP-1 and WNP-3 nuclear plants.

**Contracted Power Purchases (Line 6).** This category includes augmentation power purchases, short-term (balancing) power purchases, hedging/mitigation, the DSI benefit, and the PNCA headwater benefit. Augmentation power purchase costs reflect the energy that BPA purchases in order to satisfy its obligation to meet the load requirements for public utilities. The capped DSI benefit reflects the decision in the DSI ROD dated June 30, 2005 and the Supplemental DSI ROD released on June 1, 2006 as well as the selection of contract options during the term of the contract. The PNCA headwater benefit refers to the costs associated with benefits BPA receives from storage projects in Canada.

**Residential Exchange Program (Line 7).** This category represents the net benefits for qualifying public utilities and IOUs that are calculated as part of the Residential Exchange Program.

**Renewable and Conservation Generation (Line 8).** This category reflects the operating expenses of several generating projects fueled by renewable energy resources such as wind, geothermal, methane gas, solar, and "fish-friendly small hydro projects." It also includes the cost of conservation programs including Marketing Development, which are reimbursable contracts with equal and offsetting revenues, Market Transformation, Legacy Conservation programs, Technology Leadership, and Low-Income Weatherization.

**Transmission Acquisition and Ancillary Services (Line 9).** This category includes the annual expenses associated with PS's Transmission Acquisition program. It represents costs associated with services necessary to deliver energy from resources to markets and loads. This includes transmission, ancillary services, and real power losses, as purchased from the Transmission Business Line (TBL) or non-Federal entities, TBL costs for generation integration of COE and Reclamation projects, and metering and communication requirements.

**Power Non-Generation Operations (Line 10).** This category reflects the PS's internal costs associated with supporting the power function. It includes the costs of activities such as generation oversight, weather and streamflow forecasting, system operations planning, schedule planning, pre-scheduling, after-the-fact accounting of power transactions, power billing, customer account executives and customer service support staff, development and administration of power sales contracts, PS strategy development, PS financial reporting, analysis and budgeting, risk management, and PS human resources management.

**F&W/Environmental Requirements (Line 11).** BPA funds projects designed to accomplish measures in the NWPCC's Columbia River Basin Fish and Wildlife Program and the NOAA Fisheries Biological Opinions (BiOP). This line item includes the expense portion of BPA's fish and wildlife direct program, including staff costs and operating expenses of fish and wildlife activities. These activities include measures to implement the NWPCC's fish and wildlife program and the BiOP issued by the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (USFWS).

**General and Administrative (Line 12).** This category represents the allocated portion of BPA's Corporate General and Administrative costs, which are allocated to the business lines. Major functions besides the Executive Office are Corporate Communication, Finance, Diversity, and Safety. This category also includes Shared Services and the Civil Service Retirement System (CSRS) expense. Shared Services represents the costs for information technology services, infrastructure and maintenance, building rent, maintenance and security, mail services, personnel services, library and printing services, internal training, purchasing, and furniture. CSRS reflects the costs for the unfunded liability of the Civil Service Retirement and Disability Fund, the Employees Health Benefit Fund and the Employees Life Insurance Fund.

**Other Income, Expenses, and Adjustments (Line 13).** This category consists of the annual cost of the Flexible PF Rate Program.

**Non-Federal Debt Service (Line 14).** This category consists of third-party debt service or payment costs associated with capitalized contracts and other long-term, fixed contractual obligations. Debt service costs associated with EN projects (WNP-1, CGS, and WNP-3) make up the majority of these costs.

**Depreciation and Amortization (Line 15).** Depreciation is the annual capital recovery expense associated with FCRPS plant-in-service. Amortization is the annual capital recovery expense associated with non-revenue-producing assets. Reclamation and COE (including Lower Snake River Fish and Wildlife Compensation Plan (LSRCP) plant), including assets for fish and wildlife recovery, is depreciated by the straight-line method of calculation, using the composite service life of all projects, 75 -years. Capital equipment (office furniture and fixtures and data processing hardware and software) is also depreciated by the straight-line method using the average service lives for the particular categories of capital investment. Conservation investments are amortized over three different periods as described in Chapter 3. Legacy conservation investments prior to the FY 2002-2006 rate period are amortized using a straight-line, 20-year life. Conservation Augmentation investments in the FY 2002-2006 period are amortized using a declining life method with all amortization being complete in FY 2011. Conservation Acquisition investments beginning in FY 2007 are amortized using a straight-line, five-year life. (*See* Documentation, WP-07-FS-BPA-10A, Chapters 3 and 4.)

**Total Operating Expenses (Line 16).** Total Operating Expenses is the sum of the above expenses (Lines 2 through 15).

**Interest on Appropriated Funds (Line 19).** Interest on Appropriated Funds includes interest on COE and Reclamation appropriations as calculated in the generation repayment studies. (*See* Documentation, WP-07-FS-BPA-10A, Chapters 4 and 6.)

**Interest on Bonds Issued to U.S. Treasury (Line 20).** Interest on long-term debt includes interest on bonds that BPA issues to the U.S. Treasury to fund investments in capital equipment, conservation, fish and wildlife, and to fund Reclamation and COE investments under the Energy Policy Act of 1992 (EPA-92) (P.L. No. 102-486, 1992 U.S. Code Cong. & Admin. News, 106 Stat. 2776). The interest expense is calculated in the generation repayment studies. Any payments of call premiums for bonds projected to be amortized are included in this line. (*Id*.)

**Interest Credit on Cash Reserves (Line 21).** An interest income credit is also computed on the projected year-end cash balance in the BPA fund attributable to the Power Business Line that carries over into the next year. Also included is an interest income credit calculated in the generation repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year. Interest income is credited against bond interest. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 6.)

**Amortization of Capitalized Bond Premiums (Line 22).** When a bond issued to the U.S. Treasury is refinanced, any call premium resulting from early retirement of the original bond is capitalized and included in the principal of the new bond. The capitalized call premium is then amortized over the term of the new bond. The annual amortization is a non-cash component of interest expense.

**Capitalization Adjustment (Line 23).** Implementation of the Refinancing Act entailed a change in capitalization on BPA's financial statements. Outstanding appropriations were reduced as a result of the refinancing by $2,142 million in the generation function. The reduction is recognized annually over the remaining repayment period of the refinanced appropriations. The annual recognition of this adjustment is based on the increase in annual interest expense resulting from implementation of the Refinancing Act, as shown in repayment studies for the year of the refinancing transaction (1997). The capitalization adjustment is included on the income statement as a non-cash contra-expense.

**Allowance for Funds Used During Construction (AFUDC) (Line 24).** AFUDC is a credit against interest costs on long-term debt (Line 20). This reduction to interest costs reflects an estimate of interest on the funds used during the construction period of facilities that have yet to be placed in service. AFUDC is capitalized along with other construction costs and is recovered through rates over the expected service life of the related plant as part of the depreciation expense after the facilities are placed in service. AFUDC, which is calculated outside the generation repayment studies, is associated with the COE and BOR capital investments direct-funded by BPA.

**Net Interest Expense (Line 25).** Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 19), Interest on Bonds Issued to U.S. Treasury (Line 20), Interest Credit on Cash Reserves (Line 21), Amortization of Capitalized Bond Premiums (Line 22), Capitalization Adjustment (Line 23), and AFUDC (Line 24).

**Total Expenses (Line 26).** Total Expenses are the sum of Total Operating Expenses (Line 16) and Net Interest Expense (Line 25).

**Minimum Required Net Revenues (Line 27).** Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 5B), may be necessary to cover cash requirements in excess of accrued expenses. An explanation of the method used for determining the Minimum Required Net Revenues is included in Section 4.1.2 of this chapter.

**Planned Net Revenues for Risk (PNRR) (Line 28).** PNRR are the amount of net revenues to be included in rates for financial risk mitigation. PNRR, starting reserves, the cash-flow when non-cash expenses exceed cash payments, the CRAC, and other risk mitigation tools are available to mitigate risk in FY 2007-2009. (*See* Risk Analysis Study, WP-07-E-BPA-48.)

**Total Planned Net Revenues (Line 29).** Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 27) and PNRR (Line 28).

**Total Revenue Requirement (Line 30).** Total Revenue Requirement is the sum of Total Expenses (Line 26) and Total Planned Net Revenues (Line 28).

### 4.1.2 Statement of Cash Flows

Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 5B). Volumes 1 and 2 of Documentation, WP-07-FS-BPA-10A and WP-07-FS-BPA-10B, provide additional information related to the use and development of the data contained in the table.

**Minimum Required Net Revenues (Line 2).** Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required Net Revenues may be necessary so that the cash provided from operating activities will be sufficient to cover the planned amortization and irrigation assistance payments (the difference between Lines 8 and 21) without causing the Annual Increase (Decrease) in Cash (Line 22) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Line 27).

**Depreciation and Amortization (Line 4).** Depreciation is from the Income Statement (Table 5A, Line 15). It is included in computing Cash Provided By Operating Activities (Line 8) because it is a non-cash expense of the FCRPS.

**Amortization of Capitalized Bond Premiums (Line 5).** Amortization of capitalized bond premiums is from the Income Statement (Table 5A, line 22). It is included in computing Cash Provided By Operating Activities (Line 8) because it is a non-cash expense of the FCRPS.

**Capitalization Adjustment (Line 6).** Capitalization Adjustment is from the Income Statement (Table 5A, Line 23). It is a non-cash contra-expense.

**Accrual Revenues (Line 7).** Accrual revenues are primarily associated with settlement agreements reached in prior periods. The annual accrual revenues, which are part of the total revenues recovering the FCRPS revenue requirement, are included here as a non-cash adjustment to cash from current operations.

**Cash Provided By Operating Activities (Line 8).** Cash Provided By Current Operations, the sum of Lines 2, 4, 5, 6, and 7 is available for the year to satisfy cash requirements.

**Investment in Utility Plant (Line 11).** Investment in Utility Plant represents the annual increase in additions to appropriated plant-in-service and to capital expenditures for COE, Reclamation, and BPA construction work-in-progress funded by bonds. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 4.)

**Investment in Conservation (Line 12).** Investment in Conservation represents the annual increase in capital expenditures associated with Conservation programs. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 4.)

**Investment in Fish and Wildlife (Line 13).** Investment in Fish and Wildlife represents the annual increase in BPA's capital expenditures to fund projects designed to comply with the NWPCC's Columbia River Basin Fish and Wildlife Program and the BiOP issued by NMFS and USFWS.

**Cash Used for Investment Activities (Line 14).** Cash Used for Investment Activities is the sum of Lines 11, 12, and 13.

**Increase in Bonds Issued to U.S. Treasury (Line 16).** This category reflects the new bonds issued by BPA to the U.S. Treasury to fund capital equipment, conservation, and fish and wildlife capital programs and to direct-fund Reclamation and COE investments under the EPA-92. (*See* Documentation, WP-E-FS-BPA-46A, Chapter 7.)

**Repayment of Bonds Issued to U.S. Treasury (Line 17).** This is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury as determined in the generation repayment studies. (*See* Documentation, WP-07-FS-BPA-10B, Chapter 6.)

**Increase in Federal Construction Appropriations (Line 18).** Increase in Congressional Capital Appropriations represents Congressional appropriations projected to be received during the year for COE and Reclamation capital projects. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 4.)

**Repayment of Federal Construction Appropriations (Line 19).** Repayment of Capital Appropriations represents projected amortization of outstanding COE and Reclamation appropriations as determined in the generation repayment studies. (*See* Documentation, WP-07-FS-BPA-10B, Chapter 6.)

**Payment of Irrigation Assistance (Line 20).** Payment of Irrigation Assistance represents the payment of appropriated capital construction costs of Reclamation irrigation facilities that have been determined to be beyond the ability of the irrigators to pay and allocated to generation revenues for repayment. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 9.)

**Cash Provided by Borrowing and Appropriations (Line 21).** Cash Provided by Borrowing and Appropriations is the sum of Lines 16 through 20. This is the net cash-flow resulting from increases in cash from new long-term debt and capital appropriations and decreases in cash from repayment of long-term debt and capital appropriations.

**Annual Increase (Decrease) in Cash (Line 22).** Annual Increase (Decrease) in Cash is the sum of Lines 7, 13, and 20 and reflects the annual net cash-flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash-flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues would be insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease.

**Planned Net Revenues for Risk (PNRR) (Line 23).** PNRR reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 5A, Line 28).

**Total Annual Increase (Decrease) in Cash (Line 24).** Total Annual Increase (Decrease) in Cash in the sum of Lines 22 and 23. It is the total annual cash that is projected to be available to add to BPA's cash reserves.

## 4.2 Current Revenue Test

Consistent with RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test, Tables 6 and 7, determines whether the revenues expected from current rates can continue to meet cost recovery requirements and, therefore, be extended. Revenues at current rates can be found in the documentation of the Wholesale Power Rate Development Study (WPRDS). (*See*, WPRDS Documentation, WP-07-E-BPA-49, Section 5.) The results of the current revenue test demonstrate that current rates are inadequate to ensure cost recovery. However, this is due to not including the Residential Exchange Program benefits, which are calculated as part of the proposed rate development process. (*See* Figure 1.) Residential Exchange Benefits are not calculated under current rates.

### 4.3 Revised Revenue Test

Consistent with RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements as well as BPA's TPP standard for the rate period. The revised revenue test was conducted using the base case forecast of revenues under proposed rates. (*See* WPRDS Documentation, WP-07-E-BPA-49A, Section 5.) The test also included changes in expenses such as Residential Exchange Benefits, which is an outcome of the rate development process. (*See* Figure 1.)

As noted previously in Chapter 1, it was necessary to shift a total of $82 million in planned amortization from FY 2009 to FY 2007 and 2008 WP-07 Final Revenue Requirement Study. This action was taken because expected revenues in FY 2009, the lowest of the rate period, were significantly lower than the cash requirements in that year, the highest of the rate period. Expenses in FY 2009 are particularly high because it is a refueling year for the CGS nuclear plant. Consequently, amortization was reshaped, without changing the total planned amortization for the rate period, to accommodate the shape of the revenue forecast. The tables in Volume 2 of the Documentation display the inputs and outputs of the revised repayment study. (*See* Documentation, Volume 2, WP-07-FS-BPA-10B.)

After the completion of the rate development process, BPA revised its estimate of the cost of implementing the Residential Exchange Program, from $2 million to $1.148 million. This change was incorporated in the revised revenue test as it is the most current spending level forecast for that program.

For the rate test period, the demonstration of the adequacy of proposed rates is shown on Tables 8A (Income Statement) and 8B (Cash-Flow Statement). Table 8B, Statements of Cash

Flows, tests the sufficiency of the resulting Net Revenues from Table 8A (Line 28) for making the planned annual amortization and irrigation assistance payments and achieving the Administrator's financial objectives. This is demonstrated by the Annual Increase (Decrease) in Cash (Line 22). The annual cash-flow (Line 22) 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 the basic cost recovery requirements and meet risk mitigation policy for the rate period of FY 2007-2009.

### 4.4 Repayment Test at Proposed Rates

Table 9 demonstrates whether projected revenues from proposed rates are adequate to meet the cost recovery criteria of RA 6120.2 over the repayment period. The data are presented in a format consistent with the revised revenue tests (Tables 8A and 8B) and separate accounting analyses. The focal point of these tables 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 approval 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 greater than zero for each year of the rate approval 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 test period data have been developed specifically for this rate filing. The repayment period data are presented consistent with the requirements of RA 6120.2. Typically, the revenue test through the repayment period uses expenses from the last year of the rate period. In this case, expenses for the CGS nuclear plant were normalized because it is on a two-year refueling cycle, which results in low costs in the first year and high costs in the second year. FY 2009 is a refueling year for CGS, which increases O&M costs for the facility and power purchase costs to make up for the loss of generation during the refueling. The projection of these costs through the repayment period would misrepresent the costs associated with the CGS refueling cycle. For the purposes of this revenue test, these costs have been normalized by averaging FY 2009 with FY 2008 to produce an average cost for the operation of CGS and for augmentation.

## 5. REVENUE REQUIREMENT LEGAL REQUIREMENTS AND POLICIES

This chapter summarizes the following policies:

- The statutory framework that guides the development of BPA's revenue requirements and the allocation of FCRPS costs among the various users of the system.

- The repayment policies that BPA follows in the development of its revenue requirement.

### 5.1 Development of BPA's Revenue Requirements

BPA's revenue requirements are governed by four main legislative acts: The Bonneville Project Act of 1937, P.L. No. 75-329, 50 Stat. 731; the Flood Control Act of 1944, P.L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River Transmission System Act (Transmission System Act) of 1974, P.L. No. 93-454, 88 Stat. 1376; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), P.L. No. 96-501, 94 Stat. 2697. Other statutory provisions that guide the development of BPA's revenue requirements include the Federal Power Act, as amended by the Energy Policy Act of 1992 (EPA-92), P.L. No. 102-486, 106 Stat. 2776; the Colville Settlement Act, P.L. No. 103-436, 108 Stat. 4577; and the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, 110 Stat. 132. DOE Order "Power Marketing Administration Financial

Reporting," RA 6120.2, issued by the Secretary of Energy provides guidance to Federal power marketing agencies regarding repayment of the Federal investment.

### 5.1.1 Legal Requirements Governing the FCRPS Revenue Requirement

BPA's rates must be set in a manner that ensures revenue levels sufficient to recover fully its costs. This requirement was first set forth in Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f (amended 1977):

> Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of 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 …

Development of the FCRPS revenue requirements is a critical component of meeting this ratemaking directive. Section 9 of the Transmission System Act, 16 U.S.C, § 838g, also strongly reflects this cost recovery principle, providing that rates be set:

> [A]t 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.

Similar guidelines are provided in Section 7 of the Northwest Power Act, 16 U.S.C. § 839e. Section 7(a)(1), 16 U.S.C. § 839e(a)(1), provides:

> The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the cost 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 [Act] 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 of this [Act].

Section 7(n) of the Northwest Power Act provides additional guidance regarding cost recovery for the FY 2007-2009 rate period, and preserves BPA's ability to establish appropriate reserves subsequent to FY 2006:

> Notwithstanding any other provision of this section, rates established by the Administrator, under this section shall recover costs for protection, mitigation and enhancement of fish and wildlife, whether under the Pacific Northwest Electric Power Planning and Conservation Act or any other Act, not to exceed such amounts the Administrator forecasts will be expended during the fiscal year 2002 2006 rate period, while preserving the Administrator's ability to establish appropriate reserves and maintain a high Treasury payment probability for the subsequent rate period.

(16 U.S.C. § 839e(n).)

The Northwest Power Act also makes it clear that a primary purpose of confirmation of BPA rates by FERC is to assure that the revenue requirement is adequate to assure timely U.S. Treasury repayment. Section 7(a)(2), 16 U.S.C. § 839e(a)(2), provides:

> Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6) of this section, upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such 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.

In addition to reiterating and clarifying the cost recovery principle, the Northwest Power Act provided supplementary authority to sell bonds to the U.S. Treasury to finance BPA's new conservation and renewable resource programs. (*See* 16 U.S.C. § 838i.) The EPA-92 clarified BPA's authority to provide funds directly to the COE and Reclamation for hydroelectric generation additions, improvements, and replacements, as well as O&M expenses. (*See* P.L. No. 102-486, 1992 U.S. Code Cong. & Admin. News, 106 Stat. 2776.) Other provisions that have particular relevance to the repayment of power costs can be found in the Reclamation Project Act of 1939 (codified as amended in scattered sections of 43 U.S.C.); the Grand Coulee Dam - Third Powerplant Act of June 14, 1966, P.L. No. 89-448, 80 Stat. 200, authorizing construction of the Grand Coulee Dam Third Powerhouse; and P.L. No. 89-561, 80 Stat. 707, Act of September 7, 1966, which partially amended P. L. No. 89-448. The costs associated with these projects and programs, as well as the other costs incurred by the Administrator in furtherance of BPA's mission, are included in this Study.

#### 5.1.2 Colville Settlement Act Credits

The Confederated Tribes of the Colville Reservation Grand Coulee Dam Settlement Act approves and ratifies the Settlement Agreement entered into by the United States and the Confederated Tribes of the Colville Reservation (Colville Tribes) related to the claims for a portion of the revenues from Grand Coulee Dam, and directs BPA to carry out its obligations under the settlement agreement. (*See* P. L. No. 103-436, Nov. 2, 1994, 108 Stat. 4577.)

The Settlement Agreement obligates BPA to make annual payments to the Colville Tribes. Payments have been tied to both BPA's average prices and the amount of annual generation from Grand Coulee Dam. Under the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-13, 110 Stat. 1321, BPA receives annual credits from the U.S. Treasury against payments due the U.S. Treasury, in order to defray a portion of the costs of making payments to the Colville Tribes. Revenues credited to BPA associated with the Settlement Agreement are $17 million in FY 1999, $18 million in FY 2000, and $18 million in FY 2001. The credits for the FY 2009 are forecast to be $4.6 million in each fiscal year.

#### 5.1.3 The BPA Appropriations Refinancing Act

As in the prior rate period, BPA's power rates for the FY 2007-2009 rate period will reflect the requirements of the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, 16 U.S.C. § 838l, P.L. No. 104-134, 110 Stat. 1321, enacted in April 1996. The Refinancing Act required that unpaid principal on FCRPS 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. (*Id*. at §838l(b)(I).) The Refinancing Act also specifies 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. (*Id*. at § 838l(a)(6)(A).)

The Refinancing Act specifies that repayment periods on new principal amounts may not be earlier than determined prior to the refinancing. (*Id*. at §838l(d).)

The Refinancing Act specifies that the prevailing U.S. Treasury yield curve will be used to calculate interest during construction (IDC) and to assign interest rates to new capital investments funded by appropriations. *See*16 U.S.C. § 838l(f). New capital investments are defined as capital investments funded by appropriations for a project placed in service after September 30, 1996. (*Id*. at § 838l(a)(3).) The IDC in each fiscal year of construction for new capital investments is the prevailing one-year U.S. Treasury rate. (*Id*. at § 838l(f)(1).) The IDC is capitalized and included in the principal. After the plant is completed, the principal amount is assigned an interest rate based on the U.S. Treasury yield curve prevailing in the year in which the plant is placed in service. (*Id.* at § 838l(g).)

The U.S. Treasury rate for new capital investments prescribed in the Refinancing Act is:

> [A] rate determined by the Secretary of the Treasury, taking into consideration prevailing market yields, during the month preceding the beginning of the fiscal year in which the [new investment] … is placed in service, on outstanding interest bearing obligations of the United States with periods to maturity comparable to the period between the beginning of the fiscal year and the repayment date for the new capital investment.

(16 U.S.C. § 838l(a)(6)(B).)

The Refinancing Act also directed the Administrator to offer to provide assurance in new or existing power, transmission, or related service contracts that the government would not increase the repayment obligations in the future. (*See* 16 U.S.C. § 838l(i).) The Refinancing Act also amends the Colville Settlement Act to modify the amount and timing of certain credits that BPA takes against its annual cash transfers to U.S. Treasury.

## 5.2 Allocation of Federal Columbia River Power System (FCRPS) Costs

In addition to power production, the individual generating projects comprising the FCRPS serve other purposes, including navigation, irrigation, recreation, and flood control. The total costs of these Federal projects are generally allocated according to the purposes they serve.

For projects that provide power resources to the FCRPS, this allocation has generally been accomplished pursuant to statutory direction. For example, Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f, requires that BPA's rates be based, *inter alia*, on "an allocation of costs made by the [Secretary of Energy,]" and, insofar as costs of the Bonneville Project were concerned:

[T]he Secretary of Energy may allocate to the costs of electric facilities such a share of the cost of facilities having joint value for the production of electric energy and other purposes as the power development may fairly bear as compared with other such purposes.

> [T]he Secretary of Energy may allocate to the costs of electric facilities such a share of the cost of facilities having joint value for the production of electric energy and other purposes as the power development may fairly bear as compared with other such purposes.

(*Id.*)

Similar allocations for projects constructed pursuant to various Reclamation laws have been performed by the Secretary of the Interior under the authority of 43 U.S.C. § 485h(a)-(b). Cost allocations for projects constructed by the COE have also been performed by the Secretary of the Army and approved by the Federal Power Commission (the predecessor to FERC).

On a generic level, an attempt is made to allocate the specific cost of each feature of a multi-purpose dam to the purpose it serves. For example, the costs of powerhouses, penstocks, and other specific power-related facilities have been allocated to power, whereas the costs of navigation locks have been allocated to navigation. More problematic are the joint-use costs that remain unallocated after the specific costs identifiable to a single purpose have been allocated. The joint-use formulas attempt to account for the relative benefits provided by each function, and costs are allocated accordingly.

Thus, costs assigned to the power production functions include specific cost items whose sole purpose is power production and the "power production share" of joint costs assigned to more than one purpose. Both types of costs are included in BPA's power revenue requirement.

### 5.2.1 Section 4(h)(10)(C) Credit

The Northwest Power Act provides that:

> The Administrator shall use the Bonneville Power Administration fund and the authorities available to the Administrator under [the Northwest Power Act] and other laws administered by the Administrator to protect, mitigate, and enhance fish and wildlife to the extent affected by the development and operation of any hydroelectric project of the Columbia River and its tributaries …

(16 U.S.C. § 839b(h)(10)(A).)

BPA is not obligated to reimburse the U.S. Treasury for the non-power portion of these fish and wildlife costs. Such non-power costs are instead allocated to the various project purposes by the BPA Administrator, in consultation with the COE and Reclamation, pursuant to Section 4(h)(10)(C) of the Northwest Power Act. 16 U.S.C. § 839b(h)(10)(C). This allocation to various project purposes is intended to implement the principle that electric power consumers bear no greater share of the costs of fish and wildlife mitigation than the power portion of the project.

The legislative history of section 4(h)(10)(C) illustrates how the expenditures by the Administrator for protection, mitigation, and enhancement of fish and wildlife at individual Federal projects in excess of the portion allocable to electric consumers is to be treated as a credit for electric consumers. (*See* H.R. Rep. No. 976, 96th Cong., 2d Sess., pt. 2 at 45 (1980), reprinted in 1980 U.S.C.C.A.N. 5989, 6011.) This principle is satisfied by treating expenditures on behalf of non-power purposes as other project costs. These amounts are regarded as having been applied towards other project costs properly allocable to the power function and payable to the U.S. Treasury. Thus, BPA receives a credit against its cash transfers to the U.S. Treasury for expenditures attributable to other project purposes. The cost-sharing arrangements with the Administration implement the section 4(h)(10)(C) directives.

BPA's initial funding of all the costs for fish and wildlife has the advantage of avoiding the need for funding the non-power portion of these costs through the annual appropriations process. (*See* Study; WP-07-FS-BPA-02, Chapter 2.2; Wholesale Power Rate Development Study, WP-07-FS-BPA-05; Chapter 5.2.3.3, Loads and Resources Study, WP-07-FS-BPA-011, Chapter 2.6.1, Risk Analysis Study, WP-07-FS-BPA-03, Section 2.4.11, and Risk Analysis Study Documentation, WP-07-FS-BPA-03A, Section 1.5.5 for further discussion of section 4(h)(10)(C) credits.)

### 5.2.2 Equitable Allocation of Transmission Costs

In an order dated January 27, 1984, *United States Department of Energy – --Bonneville Power Admin.,* 26 FERC 61,096 (1984), FERC directed BPA to, among other things, develop separate repayment studies for the generation and transmission functions of the FCRPS. The purpose of this requirement was to assist FERC in making the determination required under section 7(a)(2)(C) of the Northwest Power Act (16 U.S.C. § 839e(a)(2)(C)) that transmission costs be equitably allocated between Federal and non-Federal use of the transmission system. This requirement has given BPA a 21-year history of conducting separate repayment studies for the transmission and generation functions, which has enabled BPA to transition to a bifurcated rate setting process with minimal change in repayment policy and development of the revenue requirement. Consistent with the decision to conduct bifurcated hearings for the transmission and generation functions beginning with the WP-02 proceeding, the Revenue Requirement Study incorporates only the separate repayment study for the generation function of the FCRPS for FY 2007-2009.

## 5.3 Repayment Requirements and Policies

The statutes do not include specific directives for scheduling repayment of the FCRPS capital appropriations and bonds issued to U.S. Treasury. The details of the repayment policy have largely been established through administrative interpretation of statutory requirements, with Congressional sanction.

There have been a number of changes in BPA's repayment policy over the years concurrent with expansion of the FCRPS and changing conditions. In general, current repayment criteria were first 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 FERC) 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 this authorization, H.R. Rep. No. 1409, 89th Cong., 2d Sess. 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's customers, which include both electric utilities and electro-process 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 are set forth in the Department of the Interior (DOI) 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 a repayment policy for all DOI power marketing agencies, of which BPA was one at the time, the Deputy Assistant Secretary issued a memo on August 2, 1972 outlining: (1) a uniform definition of the commencement 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 still complying with the repayment period established for each increment of investment.

A further clarification of the repayment policy was outlined in a joint memo of 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 or 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 DOI's power marketing agencies. Included therein are standard policies and procedures for preparing system repayment studies.

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

The repayment policy outlined in 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 each FY of obtaining power through purchase and exchange agreements, the cost for transmission services, and other costs during the year in which such costs are incurred;

(3) Pay interest each year on the unamortized portion of the commercial power investment financed with appropriated funds at the interest rates established for each generating project and for each annual increment of such investment in the BPA transmission system, except that recovery of annual interest expense may be deferred in unusual circumstances for short periods of time;

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

(5) Repay:

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

(6) As required by P.L. No. 89-448, 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 is 50 years from the year in which the plant is placed in service. The Refinancing Act overrides provisions in RA 6120.2 related to determining interest during construction and assigning interest rates to Federal investments financed by appropriations. This Refinancing Act also contains provisions on repayment periods (due dates) for these investments. s The Refinancing Act is discussed in section 5.1.3 of this chapter.

Irrigation costs are repaid without interest. P.L. No. 89-448 authorizes the payment of irrigation costs from revenues of the entire power system. This is consistent with the so-called "Basin Account" concept. P.L. No. 89-561, approved on September 7, 1966, amended P.L. No. 89-448 to provide several limitations on the repayment of irrigation costs from power revenues. These limitations are:

(1) the irrigation costs are to be paid from "net revenues" of the power system, with net revenues defined as those revenues over and above the amount needed to cover power costs and previously authorized irrigation payments;

(2) the construction of new Federal irrigation projects will be scheduled, *i.e.,* deferred, if necessary, so that the repayment of the irrigation costs from power revenues will not require an increase in the BPA power rate level; and

(3) the total amount of irrigation costs to be repaid from power revenues shall not average more than $30 million per year in any period of 20 consecutive years.

In addition, other sections within 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 still completing repayment of each increment of Federal investment and obligation within its prescribed repayment period.

## Table 5A

**GENERATION REVENUE REQUIREMENT**
**INCOME STATEMENT**
**($000s)**

| | | A 2009 |
|---|---|---|
| 1 | OPERATING EXPENSES | |
| 2 | POWER SYSTEM GENERATION RESOURCES | |
| 3 | OPERATING GENERATION RESOURCES | 586,822 |
| 4 | OPERATING GENERATION SETTLEMENT PAYMENTS | 20,909 |
| 5 | NON-OPERATING GENERATION | 2,904 |
| 6 | CONTRACTED POWER PURCHASES | 292,669 |
| 7 | RESIDENTIAL EXCHANGE PROGRAM | 2,000 |
| 8 | RENEWABLE AND CONSERVATION GENERATION | 124,481 |
| 9 | TRANSMISSION ACQUISITION AND ANCILLARY SERVICES | 175,098 |
| 10 | POWER NON-GENERATION OPERATIONS | 76,024 |
| 11 | F&W/ENVIRONMENTAL REQUIREMENTS | 229,438 |
| 12 | GENERAL AND ADMINISTRATIVE | 60,271 |
| 13 | OTHER INCOME, EXPENSES AND ADJUSTMENTS | 3,600 |
| 14 | NON-FEDERAL DEBT SERVICE | 563,720 |
| 15 | DEPRECIATION AND AMORTIZATION | 188,580 |
| 16 | TOTAL OPERATING EXPENSES | 2,326,515 |
| 17 | INTEREST EXPENSE: | |
| 18 | INTEREST ON FEDERAL INVESTMENT- | |
| 19 | APPROPRIATED FUNDS | 224,695 |
| 20 | BONDS ISSUED TO U.S. TREASURY | 51,202 |
| 21 | INTEREST CREDIT ON CASH RESERVES | (57,900) |
| 22 | AMORTIZATION OF CAPITALIZED BOND PREMIUMS | 185 |
| 23 | CAPITALIZATION ADJUSTMENT | (45,937) |
| 24 | ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION | (11,400) |
| 25 | NET INTEREST EXPENSE | 160,845 |
| 26 | TOTAL EXPENSES | 2,487,360 |
| 27 | MINIMUM REQUIRED NET REVENUES 1/ | 0 |
| 28 | PLANNED NET REVENUES FOR RISK | 0 |
| 29 | TOTAL PLANNED NET REVENUES (27+28) | 0 |
| **30** | **TOTAL REVENUE REQUIREMENT** | **2,487,360** |

1/ SEE NOTE ON CASH FLOW STATEMENT

## Table 5B

**GENERATION REVENUE REQUIREMENT**
**STATEMENT OF CASH FLOWS**
**($000s)**

| | | A 2009 |
|---|---|---|
| 1 | CASH FROM OPERATING ACTIVITIES | |
| 2 | MINIMUM REQUIRED NET REVENUES 1/ | 0 |
| 3 | NON-CASH ITEMS: | |
| 4 | DEPRECIATION AND AMORTIZATION | 188,580 |
| 5 | AMORTIZATION OF CAPITALIZED BOND PREMIUMS | 185 |
| 6 | CAPITALIZATION ADJUSTMENT | (45,937) |
| 7 | ACCRUAL REVENUES | (3,524) |
| 8 | CASH PROVIDED BY OPERATING ACTIVITIES | 139,304 |
| 9 | CASH FROM INVESTMENT ACTIVITIES: | |
| 10 | INVESTMENT IN: | |
| 11 | UTILITY PLANT (INCLUDING AFUDC) | (255,952) |
| 12 | CONSERVATION | (27,200) |
| 13 | FISH & WILDLIFE | (50,000) |
| 14 | CASH USED FOR INVESTMENT ACTIVITIESS | (333,152) |
| 15 | CASH FROM BORROWING AND APPROPRIATIONS: | |
| 16 | INCREASE IN BONDS ISSUED TO U.S. TREASURY | 327,335 |
| 17 | REPAYMENT OF BONDS ISSUED TO U.S. TREASURY | (92,990) |
| 18 | INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS | 5,817 |
| 19 | REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS | (10,075) |
| 20 | PAYMENT OF IRRIGATION ASSISTANCE | (7,279) |
| 21 | CASH PROVIDED BY BORROWING AND APPROPRIATIONS | 222,808 |
| 22 | ANNUAL INCREASE (DECREASE) IN CASH | 28,960 |
| 23 | PLANNED NET REVENUES FOR RISK | 0 |
| 24 | TOTAL ANNUAL INCREASE (DECREASE) IN CASH | 28,960 |

1/ Line 22 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 6A

**GENERATION CURRENT REVENUE TEST**
**INCOME STATEMENT**
**($000s)**

| | | 2009 |
|---|---|---|
| 1 | REVENUES FROM CURRENT RATES | 2,748,765 |
| | | |
| 2 | OPERATING EXPENSES | |
| 3 | POWER SYSTEM GENERATION RESOURCES | |
| 4 | OPERATING GENERATION RESOURCES | 586,822 |
| 5 | OPERATING GENERATION SETTLEMENT PAYMENTS | 20,909 |
| 6 | NON-OPERATING GENERATION | 2,904 |
| 7 | CONTRACTED POWER PURCHASES | 292,669 |
| 8 | RESIDENTIAL EXCHANGE 1/ | 1,148 |
| 9 | RENEWABLE AND CONSERVATION GENERATION | 124,481 |
| 10 | TRANSMISSION ACQUISITION AND ANCILLARY SERVICES | 175,098 |
| 11 | POWER NON-GENERATION OPERATIONS | 76,024 |
| 12 | F&W/ENVIRONMENTAL REQUIREMENTS | 229,438 |
| 13 | GENERAL AND ADMINISTRATIVE | 60,271 |
| 14 | OTHER INCOME, EXPENSES AND ADJUSTMENTS | 3,600 |
| 15 | NON-FEDERAL DEBT SERVICE | 563,720 |
| 16 | DEPRECIATION AND AMORTIZATION | 188,580 |
| 17 | TOTAL OPERATING EXPENSES | 2,325,663 |
| | | |
| 18 | INTEREST EXPENSE: | |
| 19 | INTEREST ON FEDERAL INVESTMENT- | |
| 20 | APPROPRIATED FUNDS | 221,992 |
| 21 | BONDS ISSUED TO U.S. TREASURY | 51,202 |
| 22 | INTEREST CREDIT ON CASH RESERVES | (57,900) |
| 23 | AMORTIZATION OF CAPITALIZED BOND PREMIUMS | 185 |
| 24 | CAPITALIZATION ADJUSTMENT | (45,937) |
| 25 | ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION | (11,400) |
| 26 | NET INTEREST EXPENSE | 158,142 |
| | | |
| 27 | TOTAL EXPENSES | 2,483,805 |
| | | |
| 28 | NET REVENUES | 264,960 |

1/ Program expense

## Table 6B

### GENERATION CURRENT REVENUE TEST
### STATEMENT OF CASH FLOWS
### ($000s)

| | | 2009 |
|---|---|---|
| 1 | CASH FROM OPERATING ACTIVITIES | |
| 2 | NET REVENUES | 264,960 |
| 3 | NON-CASH ITEMS: | |
| 4 | DEPRECIATION AND AMORTIZATION | 188,580 |
| 5 | AMORTIZATION OF CAPITALIZED BOND PREMIUMS | 185 |
| 6 | CAPITALIZATION ADJUSTMENT | (45,937) |
| 7 | ACCRUAL REVENUES | (3,524) |
| 8 | CASH PROVIDED BY OPERATING ACTIVITIES | 404,264 |
| 9 | CASH FROM INVESTMENT ACTIVITIES: | |
| 10 | INVESTMENT IN: | |
| 11 | UTILITY PLANT (INCLUDING AFUDC) | (142,817) |
| 12 | CONSERVATION | (32,000) |
| 13 | FISH & WILDLIFE | (36,000) |
| 14 | CASH USED FOR INVESTMENT ACTIVITIESS | (210,817) |
| 15 | CASH FROM BORROWING AND APPROPRIATIONS: | |
| 16 | INCREASE IN BONDS ISSUED TO U.S. TREASURY | 205,000 |
| 17 | REPAYMENT OF BONDS ISSUED TO U.S. TREASURY | (92,990) |
| 18 | INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS | 5,817 |
| 19 | REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS | (10,075) |
| 20 | PAYMENT OF IRRIGATION ASSISTANCE | (7,279) |
| 21 | CASH PROVIDED BY BORROWING AND APPROPRIATIONS | 100,473 |
| 22 | ANNUAL INCREASE (DECREASE) IN CASH | 293,920 |

# Table 7

FEDERAL COLUMBIA RIVER POWER SYSTEM
GENERATION REVENUES FROM CURRENT RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

| YEAR | A<br>REVENUES (STATEMENT A) | B<br>OPERATION & MAINTENANCE (STATEMENT E) | C<br>PURCHASE AND EXCHANGE POWER (STATEMENT E) | D<br>DEPRECIATION | E<br>NET INTEREST (STATEMENT D) | F<br>NET REVENUES (F=A-B-C-D-E) | G<br>NONCASH EXPENSES 1/ (COLUMN D) | H<br>FUNDS FROM OPERATION 2/ (H=F+G) | I<br>AMORTIZATION (REV REQ STUDY DOC,V 2,C 3) | J<br>IRRIGATION AMORTIZATION (STATEMENT C) | K<br>NET POSITION (K=H-I-J) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| COMBINED CUMULATIVE | | | | | | | | | | | |
| 1977 | 3,298,951 | 963,839 | 348,748 | 807,047 | 1,220,170 | (40,853) | 807,047 | 766,194 | 628,460 | | 137,734 |
| GENERATION | | | | | | | | | | | |
| 1978 | 217,534 | 40,331 | 51,130 | 36,511 | 81,883 | 7,679 | 46,521 | 54,200 | 6,937 | | 47,263 |
| 1979 | 189,542 | 49,347 | 25,195 | 39,083 | 98,889 | (22,972) | 42,586 | 19,614 | 914 | | 18,700 |
| 1980 | 341,863 | 76,460 | 182,743 | 41,237 | 105,740 | (64,317) | 94,441 | 30,124 | 73 | | 30,051 |
| 1981 | 502,589 | 92,990 | 269,625 | 42,870 | 118,861 | (21,757) | 48,941 | 27,184 | 4,410 3/ | | 22,774 |
| 1982 | 1,067,604 | 115,430 | 945,442 | 49,355 | 145,610 | (188,233) | 55,427 | (132,806) | 0 | | (132,806) |
| 1983 | 1,485,741 | 114,960 | 1,255,810 | 57,967 | 153,763 | (96,759) | 64,039 | (32,720) | 0 | | (32,720) |
| 1984 | 2,248,654 | 146,870 | 1,898,859 | 67,644 | 170,942 | (35,661) | 257,382 | 221,721 | 192,294 4/ | | 29,427 |
| 1985 | 2,371,829 | 137,664 | 1,898,178 | 75,711 | 173,888 | 86,388 | 75,711 | 162,099 | 37,354 | | 124,745 |
| 1986 | 2,179,326 | 135,632 | 1,895,153 | 84,162 | 175,257 | (110,878) | 84,162 | (26,716) | 10,587 | | (37,303) |
| 1987 | 2,014,040 | 154,184 | 1,826,711 | 91,552 | 199,448 | (257,855) | 91,552 | (166,303) | 2,471 | | (168,774) |
| 1988 | 2,303,479 | 183,326 | 1,796,029 | 98,288 | 204,416 | 21,420 | 98,288 | 119,708 | 149,778 | | (30,070) |
| 1989 | 2,273,508 | 173,694 | 1,760,205 | 100,104 | 189,446 | 50,059 | 100,104 | 150,163 | 32,875 | | 117,288 |
| 1990 | 2,315,035 | 198,721 | 1,527,829 | 105,338 | 197,462 | 285,685 | 105,338 | 391,023 | 63,336 | | 327,687 |
| 1991 | 2,482,482 | 216,777 | 1,572,046 | 103,047 | 167,559 | 423,053 | 103,047 | 526,100 | 114,583 | | 411,517 |
| 1992 | 2,142,645 | 287,360 | 1,821,930 | 110,403 | 169,711 | (246,759) | 110,403 | (136,356) | 57,543 | | (193,899) |
| 1993 | 2,233,989 | 309,915 | 1,868,863 | 118,143 | 186,455 | (249,387) | 118,143 | (131,244) | 117,974 | | (249,218) |
| 1994 | 2,536,059 | 316,352 | 1,934,944 | 125,396 | 197,222 | (37,855) | 125,396 | 87,541 | 135,018 | | (47,477) |
| 1995 | 2,704,285 | 327,420 | 1,915,529 | 141,798 | 215,850 | 103,688 | 141,798 | 245,486 | 196,544 | | 48,942 |
| 1996 | 2,744,510 | 366,808 | 1,959,406 | 151,122 | 208,509 | 58,665 | 154,024 | 197,689 5/ | 135,010 | | 62,679 |
| 1997 | 1,996,439 | 612,961 | 924,789 | 148,215 | 197,238 | 113,236 | 105,956 | 219,192 | 82,971 | 25,143 | 111,078 |
| 1998 | 2,060,750 | 665,005 | 1,091,678 | 162,562 | 201,930 | (60,425) | 118,892 | 76,812 | 61,000 | | 15,812 |
| 1999 | 2,366,423 | 702,717 | 1,196,308 | 162,008 | 182,079 | 123,311 | 118,951 | 311,083 | 25,000 | | 286,083 |
| 2000 | 2,720,940 | 723,377 | 1,410,029 | 165,874 | 169,320 | 252,340 | 119,184 | 366,345 | 175,338 | | 191,007 |
| 2001 | 3,888,051 | 819,270 | 2,945,886 | 168,433 | 166,504 | (212,042) | 121,506 | (143,592) | 151,062 | 16,560 | (311,214) |
| 2002 | 3,047,803 | 833,606 | 1,925,873 | 174,164 | 201,582 | (87,422) | 127,491 | (3,414) | 369,800 | | (373,214) |
| 2003 | 3,144,811 | 705,289 | 1,841,035 | 178,896 | 176,595 | 242,996 | 131,592 | 314,144 | 73,000 | | 241,144 |
| 2004 | 2,738,898 | 713,549 | 1,366,265 | 177,298 | 162,531 | 319,255 | 129,789 | 354,413 | 233,000 | 739 | 120,674 |
| 2005 | 2,814,224 | 711,713 | 1,420,735 | 186,099 | 166,610 | 329,067 | (98,072) | 320,734 | 271,301 | | 49,433 |
| 2006 | 2,853,659 | 875,605 | 1,516,332 | 181,878 | 157,609 | 122,235 | (84,357) | 355,358 | 261,276 | | 94,082 |
| 2007 | 2,657,891 | 695,564 | 1,484,767 | 176,204 | 145,516 | 155,840 | 36,175 | 289,715 | 246,300 | | 43,415 |
| COST EVALUATION PERIOD | | | | | | | | | | | |
| 2008 | 2,801,643 | 804,772 | 1,522,292 | 179,886 | 144,850 | 149,843 | 134,562 | 280,881 | 277,483 | 2,950 | 448 |
| RATE APPROVAL PERIOD | | | | | | | | | | | |
| 2009 | 2,748,765 | 912,654 | 1,224,430 | 188,580 | 158,142 | 264,959 | 142,828 | 404,263 | 103,065 | 7,279 | 293,919 |
| REPAYMENT PERIOD | | | | | | | | | | | |
| 2010 | 2,748,765 | 912,654 | 1,121,893 | 188,580 | 163,181 | 362,456 | 142,828 | 501,760 | 195,159 | 0 | 306,601 |
| 2011 | 2,748,765 | 912,654 | 1,137,706 | 188,580 | 161,073 | 348,752 | 142,828 | 488,056 | 146,592 | 34,863 | 306,601 |
| 2012 | 2,748,765 | 912,654 | 1,225,547 | 188,580 | 164,721 | 257,263 | 142,828 | 396,567 | 75,000 | 14,966 | 306,601 |
| 2013 | 2,748,765 | 912,654 | 1,168,907 | 188,580 | 167,383 | 311,241 | 142,828 | 450,545 | 132,800 | 11,141 | 306,604 |
| 2014 | 2,748,765 | 912,654 | 1,162,705 | 188,580 | 166,089 | 318,737 | 142,828 | 458,041 | 98,169 | 53,271 | 306,601 |

# Table 7 cont.

| YEAR | A<br>REVENUES<br>(STATEMENT A) | B<br>OPERATION & MAINTENANCE<br>(STATEMENT E) | C<br>PURCHASE AND EXCHANGE POWER<br>(STATEMENT E) | D<br>DEPRECIATION | E<br>NET INTEREST<br>(STATEMENT D) | F<br>NET REVENUES<br>(F=A-B-C-D-E) | G<br>NONCASH EXPENSES 1/<br>(COLUMN D) | H<br>FUNDS FROM OPERATION 2/<br>(H=F+G) | I<br>AMORTIZATION<br>(REV REQ STUDY DOC,V 2,C 3) | J<br>IRRIGATION AMORTIZATION<br>(STATEMENT C) | K<br>NET POSITION<br>(K=H-I-J) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 2,748,765 | 912,654 | 1,131,746 | 188,580 | 166,009 | 349,776 | 142,828 | 489,080 | 57,204 | 125,274 | 306,601 |
| 2016 | 2,748,765 | 912,654 | 1,266,913 | 188,580 | 171,869 | 208,750 | 142,828 | 348,054 | 0 | 41,453 | 306,601 |
| 2017 | 2,748,765 | 912,654 | 1,300,759 | 188,580 | 179,470 | 167,302 | 142,828 | 306,606 | 0 | 2 | 306,604 |
| 2018 | 2,748,765 | 912,654 | 1,133,091 | 188,580 | 182,336 | 332,105 | 142,828 | 471,409 | 136,876 | 27,931 | 306,601 |
| 2019 | 2,748,765 | 912,654 | 637,924 | 188,580 | 167,658 | 841,949 | 142,828 | 981,253 | 616,667 | 57,985 | 306,601 |
| 2020 | 2,748,765 | 912,654 | 718,591 | 188,580 | 132,723 | 796,218 | 142,828 | 935,522 | 603,966 | 24,955 | 306,601 |
| 2021 | 2,748,765 | 912,654 | 718,597 | 188,580 | 96,482 | 832,452 | 142,828 | 971,756 | 652,692 | 12,463 | 306,601 |
| 2022 | 2,748,765 | 912,654 | 718,590 | 188,580 | 56,801 | 872,141 | 142,828 | 1,011,445 | 690,189 | 14,655 | 306,601 |
| 2023 | 2,748,765 | 912,654 | 718,997 | 188,580 | 18,335 | 910,199 | 142,828 | 1,049,503 | 731,531 | 11,371 | 306,601 |
| 2024 | 2,748,765 | 912,654 | 768,715 | 188,580 | (13,542) | 892,358 | 142,828 | 1,031,662 | 707,852 | 17,209 | 306,601 |
| 2025 | 2,748,765 | 912,654 | 903,939 | 188,580 | (58,184) | 801,777 | 142,828 | 941,081 | 620,584 | 13,896 | 306,601 |
| 2026 | 2,748,765 | 912,654 | 903,715 | 188,580 | (87,647) | 831,463 | 142,828 | 970,767 | 642,916 | 21,250 | 306,601 |
| 2027 | 2,748,765 | 912,654 | 903,873 | 188,580 | (114,783) | 858,441 | 142,828 | 997,745 | 80,988 | 196,308 | 720,449 |
| 2028 | 2,748,765 | 912,654 | 904,041 | 188,580 | (115,677) | 859,167 | 142,828 | 998,471 | 54,710 | 0 | 943,761 |
| 2029 | 2,748,765 | 912,654 | 904,221 | 188,580 | (115,673) | 858,983 | 142,828 | 998,287 | 49,119 | 0 | 949,168 |
| 2030 | 2,748,765 | 912,654 | 904,413 | 188,580 | (115,668) | 858,786 | 142,828 | 998,090 | 44,228 | 0 | 953,862 |
| 2031 | 2,748,765 | 912,654 | 904,618 | 188,580 | (115,664) | 858,577 | 142,828 | 997,881 | 69,875 | 0 | 928,006 |
| 2032 | 2,748,765 | 912,654 | 904,838 | 188,580 | (117,653) | 860,346 | 142,828 | 999,650 | 36,033 | 0 | 963,617 |
| 2033 | 2,748,765 | 912,654 | 905,072 | 188,580 | (117,647) | 860,106 | 142,828 | 999,410 | 51,481 | 0 | 947,929 |
| 2034 | 2,748,765 | 912,654 | 905,322 | 188,580 | (117,641) | 859,850 | 142,828 | 999,154 | 51,949 | 0 | 947,205 |
| 2035 | 2,748,765 | 912,654 | 905,589 | 188,580 | (117,635) | 859,577 | 142,828 | 998,881 | 52,461 | 0 | 946,420 |
| 2036 | 2,748,765 | 912,654 | 905,875 | 188,580 | (117,628) | 859,284 | 142,828 | 998,588 | 52,957 | 0 | 945,631 |
| 2037 | 2,748,765 | 912,654 | 906,180 | 188,580 | (117,621) | 858,972 | 142,828 | 998,276 | 53,494 | 0 | 944,782 |
| 2038 | 2,748,765 | 912,654 | 906,507 | 188,580 | (117,613) | 858,638 | 142,828 | 997,942 | 54,070 | 0 | 943,872 |
| 2039 | 2,748,765 | 912,654 | 906,855 | 188,580 | (117,605) | 858,281 | 142,828 | 997,585 | 99,684 | 0 | 897,901 |
| 2040 | 2,748,765 | 912,654 | 907,228 | 188,580 | (120,578) | 860,881 | 142,828 | 1,000,185 | 55,280 | 0 | 944,905 |
| 2041 | 2,748,765 | 912,654 | 907,626 | 188,580 | (120,569) | 860,474 | 142,828 | 999,778 | 55,911 | 0 | 943,867 |
| 2042 | 2,748,765 | 912,654 | 908,051 | 188,580 | (120,559) | 860,039 | 142,828 | 999,343 | 56,577 | 0 | 942,766 |
| 2043 | 2,748,765 | 912,654 | 908,505 | 188,580 | (120,548) | 859,574 | 142,828 | 998,878 | 68,302 | 0 | 948,658 |
| 2044 | 2,748,765 | 912,654 | 908,991 | 188,580 | (121,531) | 860,071 | 142,828 | 999,375 | 50,220 | 0 | 952,001 |
| 2045 | 2,748,765 | 912,654 | 909,509 | 188,580 | (121,519) | 859,540 | 142,828 | 998,844 | 47,374 | 0 | 951,470 |
| 2046 | 2,748,765 | 912,654 | 910,064 | 188,580 | (121,506) | 858,972 | 142,828 | 998,276 | 44,703 | 0 | 953,573 |
| 2047 | 2,748,765 | 912,654 | 910,657 | 188,580 | (121,492) | 858,366 | 142,828 | 997,670 | 67,201 | 0 | 930,469 |
| 2048 | 2,748,765 | 912,654 | 911,289 | 188,580 | (122,994) | 859,236 | 142,828 | 998,540 | 39,862 | 0 | 958,678 |
| 2049 | 2,748,765 | 912,654 | 911,966 | 188,580 | (122,978) | 858,544 | 142,828 | 997,848 | 35,966 | 0 | 961,882 |
| 2050 | 2,748,765 | 912,654 | 912,689 | 188,580 | (122,961) | 857,804 | 142,828 | 997,108 | 32,499 | 0 | 964,609 |
| 2051 | 2,748,765 | 912,654 | 913,460 | 188,580 | (122,943) | 857,013 | 142,828 | 996,317 | 29,444 | 0 | 966,874 |
| 2052 | 2,748,765 | 912,654 | 914,285 | 188,580 | (122,923) | 856,169 | 142,828 | 995,473 | 26,740 | 0 | 968,733 |
| 2053 | 2,748,765 | 912,654 | 915,166 | 188,580 | (122,903) | 855,267 | 142,828 | 994,571 | 41,875 | 0 | 952,696 |
| 2054 | 2,748,765 | 912,654 | 916,108 | 188,580 | (122,880) | 854,303 | 142,828 | 993,607 | 42,436 | 0 | 951,171 |
| 2055 | 2,748,765 | 912,654 | 917,115 | 188,580 | (122,857) | 853,273 | 142,828 | 992,577 | 43,028 | 0 | 949,549 |
| 2056 | 2,748,765 | 912,654 | 918,190 | 188,580 | (122,831) | 852,172 | 142,828 | 991,476 | 43,649 | 0 | 947,827 |
| 2057 | 2,748,765 | 912,654 | 919,338 | 188,580 | (122,804) | 850,996 | 142,828 | 990,300 | 44,255 | 0 | 946,045 |
| 2058 | 2,748,765 | 912,654 | 920,566 | 188,580 | (122,775) | 849,740 | 142,828 | 989,044 | 44,890 | 0 | 944,154 |
| 2059 | 2,748,765 | 912,654 | 921,878 | 188,580 | (122,744) | 848,396 | 142,828 | 987,700 | 45,553 | 0 | 942,147 |
| GENERATION TOTALS | 193,889,436 | 54,289,753 | 88,447,379 | 12,375,928 | 3,878,779 | 34,897,596 | 9,449,060 | 44,501,320 | 9,709,297 | 731,665 | 32,648,650 |

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

2/MAY INCLUDE ADJUSTMENTS FOR ACCRUAL REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.

3/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

4/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

5/REDUCED BY $15,000 OF REVENUE FINANCING.

## Table 8A

**GENERATION REVISED REVENUE TEST**
**INCOME STATEMENT**
**($000s)**

| | | 2009 |
|---|---|---|
| 1 | REVENUES FROM PROPOSED RATES | 2,737,298 |
| | | |
| 2 | OPERATING EXPENSES | |
| 3 | POWER SYSTEM GENERATION RESOURCES | |
| 4 | OPERATING GENERATION RESOURCES | 586,822 |
| 5 | OPERATING GENERATION SETTLEMENT PAYMENTS | 20,909 |
| 6 | NON-OPERATING GENERATION | 2,904 |
| 7 | CONTRACTED POWER PURCHASES | 292,669 |
| 8 | RESIDENTIAL EXCHANGE 1/ | 251,416 |
| 9 | RENEWABLE AND CONSERVATION GENERATION | 124,481 |
| 10 | TRANSMISSION ACQUISITION AND ANCILLARY SERVICES | 175,098 |
| 11 | POWER NON-GENERATION OPERATIONS | 76,024 |
| 12 | F&W/ENVIRONMENTAL REQUIREMENTS | 229,438 |
| 13 | GENERAL AND ADMINISTRATIVE | 60,271 |
| 14 | OTHER INCOME, EXPENSES AND ADJUSTMENTS | 3,600 |
| 15 | NON-FEDERAL DEBT SERVICE | 563,720 |
| 16 | DEPRECIATION AND AMORTIZATION | 188,580 |
| 17 | TOTAL OPERATING EXPENSES | 2,575,931 |
| | | |
| 18 | INTEREST EXPENSE: | |
| 19 | INTEREST ON FEDERAL INVESTMENT- | |
| 20 | APPROPRIATED FUNDS | 221,992 |
| 21 | BONDS ISSUED TO U.S. TREASURY | 51,202 |
| 22 | INTEREST CREDIT ON CASH RESERVES | (57,967) |
| 23 | AMORTIZATION OF CAPITALIZED BOND PREMIUMS | 185 |
| 24 | CAPITALIZATION ADJUSTMENT | (45,937) |
| 25 | ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION | (11,400) |
| 26 | NET INTEREST EXPENSE | 158,075 |
| | | |
| 27 | TOTAL EXPENSES | 2,734,006 |
| | | |
| 28 | NET REVENUES | 3,292 |

| | | |
|---|---|---|
| 1/ | Residential Exchange Revenues | (1,686,746) |
| | Residential Exchange Expense (including program costs) | 1,954,692 |
| | IOU Residential Exchange Deemer Adjustment | (16,530) |

## Table 8B

**GENERATION REVISED REVENUE TEST**
**STATEMENT OF CASH FLOWS**
**($000s)**

| | | 2009 |
|---|---|---|
| 1 | CASH FROM OPERATING ACTIVITIES | |
| 2 | NET REVENUES | 3,292 |
| 3 | NON-CASH ITEMS: | |
| 4 | DEPRECIATION AND AMORTIZATION | 188,580 |
| 5 | AMORTIZATION OF CAPITALIZED BOND PREMIUMS | 185 |
| 6 | CAPITALIZATION ADJUSTMENT | (45,937) |
| 7 | ACCRUAL REVENUES | (3,524) |
| 8 | CASH PROVIDED BY OPERATING ACTIVITIES | 142,596 |
| 9 | CASH FROM INVESTMENT ACTIVITIES: | |
| 10 | INVESTMENT IN: | |
| 11 | UTILITY PLANT (INCLUDING AFUDC) | (142,817) |
| 12 | CONSERVATION | (32,000) |
| 13 | FISH & WILDLIFE | (36,000) |
| 14 | CASH USED FOR INVESTMENT ACTIVITIESS | (210,817) |
| 15 | CASH FROM BORROWING AND APPROPRIATIONS: | |
| 16 | INCREASE IN BONDS ISSUED TO U.S. TREASURY | 205,000 |
| 17 | REPAYMENT OF BONDS ISSUED TO U.S. TREASURY | (92,990) |
| 18 | INCREASE IN FEDERAL CONSTRUCTION APPROPRIATIONS | 5,817 |
| 19 | REPAYMENT OF FEDERAL CONSTRUCTION APPROPRIATIONS | (10,075) |
| 20 | PAYMENT OF IRRIGATION ASSISTANCE | (7,279) |
| 21 | CASH PROVIDED BY BORROWING AND APPROPRIATIONS | 100,473 |
| 22 | ANNUAL INCREASE (DECREASE) IN CASH | 32,252 |

# Table 9

FEDERAL COLUMBIA RIVER POWER SYSTEM
GENERATION REVENUES FROM PROPOSED RATES
REVENUE REQUIREMENT AND REPAYMENT STUDY RESULTS THROUGH THE REPAYMENT PERIOD
($000)

| | A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|---|
| YEAR | REVENUES (STATEMENT A) | OPERATION & MAINTENANCE (STATEMENT E) | PURCHASE AND EXCHANGE POWER (STATEMENT E) | DEPRECIATION | NET INTEREST (STATEMENT 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,V 2,C 3) | IRRIGATION AMORTIZATION (STATEMENT C) | NET POSITION (K=H-I-J) |
| COMBINED CUMULATIVE | | | | | | | | | | | |
| 1977 | 3,298,951 | 963,839 | 348,748 | 807,047 | 1,220,170 | (40,853) | 807,047 | 766,194 | 628,460 | | 137,734 |
| GENERATION | | | | | | | | | | | |
| 1978 | 217,534 | 40,331 | 51,130 | 36,511 | 81,883 | 7,679 | 46,521 | 54,200 | 6,937 | | 47,263 |
| 1979 | 189,542 | 49,347 | 25,195 | 39,083 | 98,889 | (22,972) | 42,586 | 19,614 | 914 | | 18,700 |
| 1980 | 341,863 | 76,460 | 182,743 | 41,237 | 105,740 | (64,317) | 94,441 | 30,124 | 73 | | 30,051 |
| 1981 | 502,589 | 92,990 | 269,625 | 42,870 | 118,861 | (21,757) | 48,941 | 27,184 | 4,410 3/ | | 22,774 |
| 1982 | 1,067,604 | 115,430 | 945,442 | 49,355 | 145,610 | (188,233) | 55,427 | (132,806) | 0 | | (132,806) |
| 1983 | 1,485,741 | 114,960 | 1,255,810 | 57,967 | 153,763 | (96,759) | 64,039 | (32,720) | 0 | | (32,720) |
| 1984 | 2,248,654 | 146,870 | 1,898,859 | 67,644 | 170,942 | (35,661) | 257,382 | 221,721 | 192,294 4/ | | 29,427 |
| 1985 | 2,371,829 | 137,664 | 1,898,178 | 75,711 | 173,888 | 86,388 | 75,711 | 162,099 | 37,354 | | 124,745 |
| 1986 | 2,179,326 | 135,632 | 1,895,153 | 84,162 | 175,257 | (110,878) | 84,162 | (26,716) | 10,587 | | (37,303) |
| 1987 | 2,014,040 | 154,184 | 1,826,711 | 91,552 | 199,448 | (257,855) | 91,552 | (166,303) | 2,471 | | (168,774) |
| 1988 | 2,303,479 | 183,326 | 1,796,029 | 98,288 | 204,416 | 21,420 | 98,288 | 119,708 | 149,778 | | (30,070) |
| 1989 | 2,273,508 | 173,694 | 1,760,205 | 100,104 | 189,446 | 50,059 | 100,104 | 150,163 | 32,875 | | 117,288 |
| 1990 | 2,315,035 | 198,721 | 1,527,829 | 105,338 | 197,462 | 285,685 | 105,338 | 391,023 | 63,336 | | 327,687 |
| 1991 | 2,482,482 | 216,777 | 1,572,046 | 103,047 | 167,559 | 423,053 | 103,047 | 526,100 | 114,583 | | 411,517 |
| 1992 | 2,142,645 | 287,360 | 1,821,930 | 110,403 | 169,711 | (246,759) | 110,403 | (136,356) | 57,543 | | (193,899) |
| 1993 | 2,233,989 | 309,915 | 1,868,863 | 118,143 | 186,455 | (249,387) | 118,143 | (131,244) | 117,974 | | (249,218) |
| 1994 | 2,536,059 | 316,352 | 1,934,944 | 125,396 | 197,222 | (37,855) | 125,396 | 87,541 | 135,018 | | (47,477) |
| 1995 | 2,704,285 | 327,420 | 1,915,529 | 141,798 | 215,850 | 103,688 | 141,798 | 245,486 | 196,544 | | 48,942 |
| 1996 | 2,744,510 | 366,808 | 1,959,406 | 151,122 | 208,509 | 58,665 | 154,024 | 197,689 5/ | 135,010 | | 62,679 |
| 1997 | 1,996,439 | 612,961 | 924,789 | 148,215 | 197,238 | 113,236 | 105,956 | 219,192 | 82,971 | 25,143 | 111,078 |
| 1998 | 2,060,750 | 665,005 | 1,091,678 | 162,562 | 201,930 | (60,425) | 118,892 | 76,812 | 61,000 | | 15,812 |
| 1999 | 2,366,423 | 702,717 | 1,196,308 | 162,008 | 182,079 | 123,311 | 118,951 | 311,083 | 25,000 | | 286,083 |
| 2000 | 2,720,940 | 723,377 | 1,410,029 | 165,874 | 169,320 | 252,340 | 119,184 | 366,345 | 175,338 | | 191,007 |
| 2001 | 3,888,051 | 819,270 | 2,945,886 | 168,433 | 166,504 | (212,042) | 121,506 | (143,592) | 151,062 | 16,560 | (311,214) |
| 2002 | 3,047,803 | 833,606 | 1,925,873 | 174,164 | 201,582 | (87,422) | 127,491 | (3,414) | 369,800 | | (373,214) |
| 2003 | 3,144,811 | 705,289 | 1,841,035 | 178,896 | 176,595 | 242,996 | 131,592 | 314,144 | 73,000 | | 241,144 |
| 2004 | 2,738,898 | 713,549 | 1,366,265 | 177,298 | 162,531 | 319,255 | 129,789 | 354,413 | 233,000 | 739 | 120,674 |
| 2005 | 2,814,224 | 711,713 | 1,420,735 | 186,099 | 166,610 | 329,067 | (98,072) | 320,734 | 271,301 | | 49,433 |
| 2006 | 2,853,659 | 875,605 | 1,516,332 | 181,878 | 157,609 | 122,235 | (84,357) | 355,358 | 261,276 | | 94,082 |
| 2007 | 2,657,891 | 695,564 | 1,484,767 | 176,204 | 145,516 | 155,840 | 36,175 | 289,715 | 246,300 | | 43,415 |
| COST EVALUATION PERIOD | | | | | | | | | | | |
| 2008 | 2,801,643 | 804,772 | 1,522,292 | 179,886 | 144,850 | 149,843 | 134,562 | 280,881 | 277,483 | 2,950 | 448 |
| RATE APPROVAL PERIOD | | | | | | | | | | | |
| 2009 | 2,737,298 | 912,654 | 1,474,698 | 188,580 | 158,075 | 3,291 | 142,828 | 142,595 | 103,065 | 7,279 | 32,251 |
| REPAYMENT PERIOD | | | | | | | | | | | |
| 2010 | 2,737,298 | 912,654 | 1,372,161 | 188,580 | 159,505 | 104,397 | 142,828 | 243,701 | 195,159 | 0 | 48,542 |
| 2011 | 2,737,298 | 912,654 | 1,387,974 | 188,580 | 157,397 | 90,693 | 142,828 | 229,997 | 146,592 | 34,863 | 48,542 |
| 2012 | 2,737,298 | 912,654 | 1,475,815 | 188,580 | 161,045 | (796) | 142,828 | 138,508 | 75,000 | 14,966 | 48,542 |
| 2013 | 2,737,298 | 912,654 | 1,419,175 | 188,580 | 163,707 | 53,182 | 142,828 | 192,486 | 132,800 | 11,141 | 48,545 |
| 2014 | 2,737,298 | 912,654 | 1,412,973 | 188,580 | 162,413 | 60,678 | 142,828 | 199,982 | 98,169 | 53,271 | 48,542 |

# Table 9 cont.

| YEAR | A<br>REVENUES<br>(STATEMENT A) | B<br>OPERATION &<br>MAINTENANCE<br>(STATEMENT E) | C<br>PURCHASE<br>AND<br>EXCHANGE<br>POWER<br>(STATEMENT E) | D<br>DEPRECIATION | E<br>NET<br>INTEREST<br>(STATEMENT D) | F<br>NET<br>REVENUES<br>(F=A-B-C-D-E) | G<br>NONCASH<br>EXPENSES 1/<br>(COLUMN D) | H<br>FUNDS<br>FROM<br>OPERATION 2/<br>(H=F+G) | I<br>AMORTIZATION<br>(REV REQ STUDY<br>DOC,V 2,C 3) | J<br>IRRIGATION<br>AMORTIZATION<br>(STATEMENT C) | K<br>NET<br>POSITION<br>(K=H-I-J) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2015 | 2,737,298 | 912,654 | 1,382,014 | 188,580 | 162,333 | 91,717 | 142,828 | 231,021 | 57,204 | 125,274 | 48,542 |
| 2016 | 2,737,298 | 912,654 | 1,517,181 | 188,580 | 168,193 | (49,309) | 142,828 | 89,995 | 0 | 41,453 | 48,542 |
| 2017 | 2,737,298 | 912,654 | 1,551,027 | 188,580 | 175,794 | (90,757) | 142,828 | 48,547 | 0 | 2 | 48,545 |
| 2018 | 2,737,298 | 912,654 | 1,383,359 | 188,580 | 178,660 | 74,045 | 142,828 | 213,350 | 136,876 | 27,931 | 48,542 |
| 2019 | 2,737,298 | 912,654 | 888,192 | 188,580 | 163,982 | 583,890 | 142,828 | 723,194 | 616,667 | 57,985 | 48,542 |
| 2020 | 2,737,298 | 912,654 | 968,859 | 188,580 | 129,047 | 538,159 | 142,828 | 677,463 | 603,966 | 24,955 | 48,542 |
| 2021 | 2,737,298 | 912,654 | 968,865 | 188,580 | 92,806 | 574,393 | 142,828 | 713,697 | 652,692 | 12,463 | 48,542 |
| 2022 | 2,737,298 | 912,654 | 968,858 | 188,580 | 53,125 | 614,082 | 142,828 | 753,386 | 690,189 | 14,655 | 48,542 |
| 2023 | 2,737,298 | 912,654 | 969,265 | 188,580 | 14,659 | 652,140 | 142,828 | 791,444 | 731,531 | 11,371 | 48,542 |
| 2024 | 2,737,298 | 912,654 | 1,018,983 | 188,580 | (17,218) | 634,299 | 142,828 | 773,603 | 707,852 | 17,209 | 48,542 |
| 2025 | 2,737,298 | 912,654 | 1,154,207 | 188,580 | (61,860) | 543,718 | 142,828 | 683,022 | 620,584 | 13,896 | 48,542 |
| 2026 | 2,737,298 | 912,654 | 1,153,983 | 188,580 | (91,323) | 573,404 | 142,828 | 712,708 | 642,916 | 21,250 | 48,542 |
| 2027 | 2,737,298 | 912,654 | 1,154,141 | 188,580 | (118,459) | 600,382 | 142,828 | 739,686 | 80,988 | 196,308 | 462,390 |
| 2028 | 2,737,298 | 912,654 | 1,154,309 | 188,580 | (119,353) | 601,108 | 142,828 | 740,412 | 54,710 | 0 | 685,702 |
| 2029 | 2,737,298 | 912,654 | 1,154,489 | 188,580 | (119,349) | 600,924 | 142,828 | 740,228 | 49,119 | 0 | 691,109 |
| 2030 | 2,737,298 | 912,654 | 1,154,681 | 188,580 | (119,344) | 600,727 | 142,828 | 740,031 | 44,228 | 0 | 695,803 |
| 2031 | 2,737,298 | 912,654 | 1,154,886 | 188,580 | (119,340) | 600,518 | 142,828 | 739,822 | 69,875 | 0 | 669,947 |
| 2032 | 2,737,298 | 912,654 | 1,155,106 | 188,580 | (121,329) | 602,287 | 142,828 | 741,591 | 36,033 | 0 | 705,558 |
| 2033 | 2,737,298 | 912,654 | 1,155,340 | 188,580 | (121,323) | 602,047 | 142,828 | 741,351 | 51,481 | 0 | 689,870 |
| 2034 | 2,737,298 | 912,654 | 1,155,590 | 188,580 | (121,317) | 601,791 | 142,828 | 741,095 | 51,949 | 0 | 689,146 |
| 2035 | 2,737,298 | 912,654 | 1,155,857 | 188,580 | (121,311) | 601,518 | 142,828 | 740,822 | 52,461 | 0 | 688,361 |
| 2036 | 2,737,298 | 912,654 | 1,156,143 | 188,580 | (121,304) | 601,225 | 142,828 | 740,529 | 52,957 | 0 | 687,572 |
| 2037 | 2,737,298 | 912,654 | 1,156,448 | 188,580 | (121,297) | 600,913 | 142,828 | 740,217 | 53,494 | 0 | 686,723 |
| 2038 | 2,737,298 | 912,654 | 1,156,775 | 188,580 | (121,289) | 600,579 | 142,828 | 739,883 | 54,070 | 0 | 685,813 |
| 2039 | 2,737,298 | 912,654 | 1,157,123 | 188,580 | (121,281) | 600,222 | 142,828 | 739,526 | 99,684 | 0 | 639,842 |
| 2040 | 2,737,298 | 912,654 | 1,157,496 | 188,580 | (124,254) | 602,822 | 142,828 | 742,126 | 55,280 | 0 | 686,846 |
| 2041 | 2,737,298 | 912,654 | 1,157,894 | 188,580 | (124,245) | 602,415 | 142,828 | 741,719 | 55,911 | 0 | 685,808 |
| 2042 | 2,737,298 | 912,654 | 1,158,319 | 188,580 | (124,235) | 601,980 | 142,828 | 741,284 | 56,577 | 0 | 684,707 |
| 2043 | 2,737,298 | 912,654 | 1,158,773 | 188,580 | (124,224) | 601,515 | 142,828 | 740,819 | 68,302 | 0 | 690,599 |
| 2044 | 2,737,298 | 912,654 | 1,159,259 | 188,580 | (125,207) | 602,012 | 142,828 | 741,316 | 50,220 | 0 | 693,942 |
| 2045 | 2,737,298 | 912,654 | 1,159,777 | 188,580 | (125,195) | 601,481 | 142,828 | 740,785 | 47,374 | 0 | 693,411 |
| 2046 | 2,737,298 | 912,654 | 1,160,332 | 188,580 | (125,182) | 600,913 | 142,828 | 740,217 | 44,703 | 0 | 695,514 |
| 2047 | 2,737,298 | 912,654 | 1,160,925 | 188,580 | (125,168) | 600,307 | 142,828 | 739,611 | 67,201 | 0 | 672,410 |
| 2048 | 2,737,298 | 912,654 | 1,161,557 | 188,580 | (126,670) | 601,177 | 142,828 | 740,481 | 39,862 | 0 | 700,619 |
| 2049 | 2,737,298 | 912,654 | 1,162,234 | 188,580 | (126,654) | 600,485 | 142,828 | 739,789 | 35,966 | 0 | 703,823 |
| 2050 | 2,737,298 | 912,654 | 1,162,957 | 188,580 | (126,637) | 599,745 | 142,828 | 739,049 | 32,499 | 0 | 706,550 |
| 2051 | 2,737,298 | 912,654 | 1,163,728 | 188,580 | (126,619) | 598,954 | 142,828 | 738,258 | 29,444 | 0 | 708,815 |
| 2052 | 2,737,298 | 912,654 | 1,164,553 | 188,580 | (126,599) | 598,110 | 142,828 | 737,414 | 26,740 | 0 | 710,674 |
| 2053 | 2,737,298 | 912,654 | 1,165,434 | 188,580 | (126,579) | 597,208 | 142,828 | 736,512 | 41,875 | 0 | 694,637 |
| 2054 | 2,737,298 | 912,654 | 1,166,376 | 188,580 | (126,556) | 596,244 | 142,828 | 735,548 | 42,436 | 0 | 693,112 |
| 2055 | 2,737,298 | 912,654 | 1,167,383 | 188,580 | (126,533) | 595,214 | 142,828 | 734,518 | 43,028 | 0 | 691,490 |
| 2056 | 2,737,298 | 912,654 | 1,168,458 | 188,580 | (126,507) | 594,113 | 142,828 | 733,417 | 43,649 | 0 | 689,768 |
| 2057 | 2,737,298 | 912,654 | 1,169,606 | 188,580 | (126,480) | 592,937 | 142,828 | 732,241 | 44,255 | 0 | 687,986 |
| 2058 | 2,737,298 | 912,654 | 1,170,834 | 188,580 | (126,451) | 591,681 | 142,828 | 730,985 | 44,890 | 0 | 686,095 |
| 2059 | 2,737,298 | 912,654 | 1,172,146 | 188,580 | (126,420) | 590,337 | 142,828 | 729,641 | 45,553 | 0 | 684,088 |
| GENERATION TOTALS | 193,361,954 | 54,289,753 | 99,959,707 | 12,375,928 | 3,713,292 | 23,023,273 | 9,449,060 | 32,626,997 | 9,709,297 | 731,665 | 20,774,327 |

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

2/MAY INCLUDE ADJUSTMENTS FOR ACCRUAL REVENUES OR OTHER ACCRUAL TO CASH ADJUSTMENTS.

3/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

4/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

5/REDUCED BY $15,000 OF REVENUE FINANCING.

# APPENDIX A

# INTEGRATED PROGRAM REVIEW

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**Department of Energy**

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FINANCE

July 23, 2008

In reply refer to: F-2

To Customers, Constituents, Tribes and Other Stakeholders:

The Bonneville Power Administration (BPA) is now concluding the Integrated Program Review (IPR) review of FY 2009 Power Costs, which began on May 15, 2008. After the opening "Overview" workshop that covered both Power and Transmission costs through FY 2011, seven technical workshops were held over a two-week period, covering all costs affecting the Power FY 2009 program levels. A management-level meeting was held June 11, 2008, to allow the Administrator to hear comments personally, and a public comment period was held from May 15, through June 19, 2008. Through this process, BPA sought to provide interested parties with meaningful opportunities to examine, understand, and provide input on the cost projections that would form the basis for the final Supplemental Proposal for FY 2009 Power rates, which is expected in September 2008.

Several of the comments BPA received noted that more time should have been factored into this process, and that BPA should provide alternative scenarios to participants for evaluation and comment. We agree that allowing both more time and providing options can facilitate meaningful comment, and for the upcoming review of the FY 2010-2011 Power and Transmission program levels we will be doing both of those things. Unfortunately, circumstances required that we conduct an expedited process in order for decisions to be made prior to development of BPA's final Supplemental Proposal for FY 2009 Power rates. This expedited process, in the midst of numerous other processes, meant that participants did not have as much time as would be ideal to examine and comment on these program levels. Nonetheless, BPA found this process to be beneficial and appreciates the time, energy and attention participants gave to this effort.

BPA and its partner agencies set spending levels for the FY 2007-2009 power rate period in the 2005-2006 Power Function Review, and are holding costs to those levels through the end of FY 2008. We put great emphasis on managing our costs to the levels we include in rates, and do not deviate from those levels unless there are compelling reasons to do so. After much deliberation and consideration of your input, we have reluctantly concluded that the business and regulatory environment has changed sufficiently that we do not believe we can maintain the FY 2009 programs at the levels proposed in the Power Function Review without seriously jeopardizing the ability of BPA to meet its obligations, including providing reliable and cost-effective power to the region. BPA's proposed program levels reflect the need to invest in an aging Federal hydro system, improve reliability and safety at Columbia Generating Station, and meet increasing environmental and regulatory obligations and safety and security needs, as well as internal infrastructure necessary to support the business.

The program levels included in the attached report represent BPA's decisions after carefully considering the comments received. Partly in response to comments on the draft IPR spending levels, we have identified reductions in internal costs and in conservation that we believe will not reduce the long-term capability of Power programs. These reductions, along with same changes in capital costs unrelated to IPR decisions, will decrease FY 2009 expenses by roughly $12 million compared to draft IPR levels, and are detailed in the enclosed report. We will continue to look for ways to achieve program results efficiently and effectively.

Thank you very much for your attention and input to the Integrated Program Review for FY 2009 Power costs. We look forward to your continued involvement in the ongoing IPR process on FY 2010 and 2011 Power and Transmission costs. For further information on the IPR or other issues, please contact your customer account executive, constituent account executive, tribal account executive, or me at (503) 230-5111. The final IPR report and additional information on the process is available at http://www.bpa.gov/corporate/Finance/IBR/IPR/.

Sincerely,

*/s/ David J. Armstrong, 7/23/2008*

David J. Armstrong
Executive Vice President and Chief Financial Officer

Enclosure:
Close-out Report

# Bonneville Power Administration
# Integrated Program Review
# FY 2009 Power Program Levels
# Final Report
# July 18, 2008

BONNEVILLE
POWER ADMINISTRATION

# Integrated Program Review Final Report for
# FY 2009 Power Program Levels

**Introduction and Background**

In response to customer input in the Regional Dialogue process, BPA designed its "Integrated Program Review" (IPR), a process which consolidates the prior program level review processes into one, replacing the Capital Program Review, Power Function Review and Transmission's Programs in Review. The IPR process is designed to allow interested parties to see all agency expense and capital spending level estimates in the same forum. BPA intends to hold an IPR every two years or just prior to each rate case. This will provide interested parties with an opportunity to review and comment on BPA's program level estimates prior to their use in setting rates.

BPA began its first IPR process in May 2008, focusing on FY 2010 and 2011 program levels for both Power and Transmission. This IPR also included a review of proposed Power FY 2009 program levels. The review of the FY 2009 Power program levels was expedited, with deadlines for concluding review of FY 2010-2011 program levels continuing for an additional period of time. BPA received various comments, and this report addresses those comments and outlines BPA's conclusions. Results from this report will be used in the final proposal of the WP-07 Supplemental Rate Proceeding currently being conducted.

BPA held its IPR "kickoff" workshop May 15. Workshops on each program that impacts FY 2009 Power costs were held by the end of May. The comment period for these program levels was from May 15 to June 19. The comment period included a meeting on June 11, 2008, at which General Managers of BPA's utility customers were invited to provide comments.

The initial WP-07 Supplemental Proposal, published in January 2008, forecasted significant decreases in residential exchange costs while most other program levels were held to the same levels as those in the original WP-07 rate case. BPA witnesses in the WP-07 Supplemental rate case explained that Fish and Wildlife Program cost levels could be revised for the final proposal to reflect any expected cost impacts resulting from the new Biological Opinion and potential Memoranda of Agreements with some states and tribes. BPA explained that it would review all proposed spending levels and reflect appropriate changes in the Final Proposal, but that most levels were not expected to need revision.

As BPA's spending forecasts for FY 2009 were being developed, however, it became clear that many FY 2009 spending levels forecast in FY 2006 for 2007-2009 power rates were likely to increase. In-depth assessment and analysis of the condition of the aging Federal hydro system has highlighted the need for increased investment and maintenance of that aging system. Energy Northwest (EN) believes significant additional investments are needed to improve the safety and reliability of Columbia Generating Station (CGS). While internal operations costs recovered in power rates have been held essentially flat for seven years through BPA's Enterprise Process Improvement Project (EPIP) and other cost-control efforts, there are greater than expected pressures from changing environmental obligations, regulatory and control requirements, safety and security needs, and internal infrastructure necessary to support changes in the business environment and the expanded capital program. Therefore, BPA believes that program levels will need to increase beyond the levels previously forecast.

BPA's preliminary internal development of FY 2009 spending forecasts occurred prior to the development of the Final WP-07 Supplemental Proposal. As the need for increased costs in some areas became clear, in light of the recent *Golden Northwest v. BPA*, 501 F.3d 1037 (9th Cir. 2007) BPA decided it could not include forecasts that it knew to be inaccurate in its Supplemental Power Rate Proposal. Consequently, BPA's initial IPR proposal reflected numerous areas of increased costs.

Throughout the four days of public workshops on program levels that impact FY 2009 Power costs, participants were given extensive information on BPA's programs and the drivers of proposed cost increases. Participants put a great deal of effort into fact-finding, submitting questions and requesting additional information on areas of interest. Despite the compressed timeframe, customers, constituents and other interested parties provided thoughtful comment on BPA's proposed program levels. BPA has considered those comments and has made some difficult decisions. While BPA believes it is not prudent to reduce all the program levels presented in the IPR, as some comments suggest, BPA is reducing planned costs in two areas.

**Summary of Decisions**

BPA heard participants' concern over the increasing levels of internal operating costs. BPA has determined it will reduce the proposed spending to a level BPA believes can be sustained without reducing significantly the achievement of program goals. In addition, BPA identified two reductions in the Conservation program forecasts it believes will not negatively impact the future capability of the program.

- For Power and Agency Service internal operations, proposed levels have been reduced by 3 percent.
- The Conservation Rate Credit is reduced by $4 million.
- The capital investment forecast for Conservation is reduced by $10 million.

These changes result in a decrease of roughly $8 million from the FY 2009 Power spending levels shown in the initial IPR.

Additionally, there are changes in forecasts of net interest, amortization/depreciation, and non-Federal debt service that are included in this report for information. These are not decided in the IPR process, and final forecasts will be determined in the Final Supplemental Rate Proposal. The changes in the values from the Initial IPR and the Supplemental Rate Case are due to several debt-related changes other than decisions made in this process, such as updated forecasts of FY 2008 capital investment. Debt Management is described at the end of this report, along with Power Purchases, Transmission Purchases and Reserve and Ancillary Services, and the Residential

Exchange Program, all of which will be determined in the Final Supplemental Rate Proposal.

The following summary tables provide the change in expense forecasts from the original FY 2007-2009 rate proposal, the initial IPR, and this Final Report.

Throughout this document, dollar amounts are shown in $thousands.

**Power Expenses**

| | 2009 in WP-07 Rate Case | Supplemental Rate Case | Initial IPR | Final IPR Forecast | Change between Initial IPR and Final IPR |
|---|---|---|---|---|---|
| **Power Program** | **FY 2009** | **FY 2009** | **FY 2009** | **FY 2009** | **FY 2009** |
| Columbia Generating Station O&M | 242,842 | 274,342 | 293,700 | 293,700 | 0 |
| Corps & Reclamation O&M for Hydro Projects | 248,173 | 248,173 | 261,600 | 261,600 | 0 |
| Long Term Generation Program | 25,751 | 31,864 | 31,613 | 31,522 | (91) |
| Renewables (incl rate credit) | 41,917 | 53,414 | 43,955 | 43,955 | 0 |
| Generation Conservation (including Conservation Rate Credit) | 70,347 | 79,414 | 84,526 | 80,526 | (4,000) |
| Internal Operations | 111,566 | 111,566 | 125,030 | 121,018 | (4,012) |
| Pension & Post-Retirement Benefits | 15,375 | 15,375 | 15,277 | 15,277 | 0 |
| Fish & Wildlife/USF&W/NWPCC | 173,353 | 173,367 | 229,439 | 229,439 | 0 |
| Other – Colville Settlement, Non-Operating Generation | 24,649 | 21,049 | 27,413 | 27,413 | 0 |
| Total | 2,698,421 | 2,615,184 | 2,730,011 | 2,717,549 | (8,103) |

**Power Capital**

| $ in Thousands | 2009 in WP-07 Rate Case | Supplemental Rate Case | Initial IPR | Final IPR | Change Between Initial IPR and Final IPR |
|---|---|---|---|---|---|
| **Description** | **FY 2009** | **FY 2009** | **FY 2009** | **FY 2009** | **FY 2009** |
| **Corps of Engineers/Bureau of Reclamation** | 137,000 | 137,000 | 154,950 | 154,950 | 0 |
| **Fish & Wildlife** | 36,000 | 36,000 | 50,000 | 50,000 | 0 |
| **Conservation** | 32,000 | 32,000 | 42,000 | 32,000 | -10,000 |
| **CGS** | 27,700 | 27,700 | 96,700 | 96,700 | 0 |
| **CRFM** | 62,400 | 62,400 | 63,000 | 111,000 | 48,000 |
| **15% lapse factor**[1/] | | | (29,813) | (28,313) | 1,500 |
| **Total Capital** | 295,100 | 295,100 | 376,837 | 416,337 | 39,500 |

1/ Excludes CGS, CRFM, Fish & Wildlife

## Agency Services

The following table provides the Agency Services program levels. These program levels in total will be reduced by 3 percent. (Approximately 40 percent of Agency Services costs are allocated to Power, the remaining 60 percent to Transmission.) The actual distribution and means of meeting that three percent reduction will be determined by Executive Management in order to achieve this lower level of spending.

**Agency Services Costs**

| Expenses - Direct & Allocated | Rate Case | Initial IPR | Final IPR | Change Between Initial IPR and Final IPR |
|---|---|---|---|---|
| | FY 2009 | FY 2009 | FY 2009 | 2009 |
| Executive Office | 1,030 | 1,069 | 1,069 | 0 |
| Deputy Administrator | 271 | 279 | 279 | 0 |
| Chief Risk Officer | 5,136 | 5,871 | 5,871 | 0 |
| Technology Innovation & Confirmation | 3,373 | 9,916 | 9,916 | 0 |
| Chief Public Affairs Office | 18,379 | 17,439 | 17,439 | 0 |
| Internal Audit | 1,930 | 2,384 | 2,384 | 0 |
| Finance | 13,782 | 15,224 | 15,224 | 0 |
| Corporate Strategy | 340 | 303 | 303 | 0 |
| Supply Chain Policy & Gov. | 686 | 667 | 667 | 0 |
| Regulatory Affairs | 1,829 | 2,327 | 2,327 | 0 |
| Strategic Planning | 1,771 | 1,913 | 1,913 | 0 |
| Strategy Integration | 7,510 | 7,604 | 7,604 | 0 |
| Security & Emergency Mgmt | 7,042 | 7,404 | 7,404 | 0 |
| General Counsel | 9,014 | 9,514 | 9,514 | 0 |
| Chief Operating Officer | 3,254 | 3,507 | 3,507 | 0 |
| Customer Support Services | 8,224 | 9,776 | 9,776 | 0 |
| Internal Business Services | 576 | 576 | 576 | 0 |
| Business and Process Mgmt | n/a | n/a | n/a | n/a |
| Civil Rights | 725 | 725 | 725 | 0 |
| Safety | 2,386 | 2,314 | 2,314 | 0 |
| Human Capital Management | 16,472 | 16,228 | 16,228 | 0 |
| Supply Chain Services | 16,987 | 18,315 | 18,315 | 0 |
| Workplace Services | 26,813 | 32,508 | 32,508 | 0 |
| Information Technology | 58,313 | 58,313 | 58,313 | 0 |
| Undistributed Reduction[1] | (8,386) | | (6,725) | (6,725) |
| **Total** | 197,457 | 224,175 | 217,450 | (6,725) |

[1] Rate Case amount shown here reflect an analytical "reformulation" effort done in FY 2006 to create spending levels that both tied to the Power and Transmission Rate Cases and that incorporated the impacts of reorganizations made up to that time. An undistributed reduction was included in this reformulation.

[2] Part of the program estimate increase from the rate case to current estimates for FY 09 is the result of transfers of functions and resources from Power and Transmission to Agency Services. These transfers include: $6M in Research and Development from Power and Transmission: $2.1M in non-electric plant maintenance funds from transmission; and $0.3M in training funds from Power and Transmission.

The following pages outline the comments received from IPR participants about each of the program areas, noting any changes BPA has made between the initial IPR and this Final Report as a result of these comments. Unless otherwise noted, "Original WP-07" refers to the value reflected in the July 2006 Final Power Rate Proposal for FY 2009.

## A. Columbia Generating Station (CGS)

**Expense**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 242,842 | 293,700 | 293,700 |

**Capital**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 27,700 | 96,700 | 96,700 |

BPA pays the costs of Energy Northwest's CGS nuclear power plant. EN management is focusing on equipment obsolescence, reliability and plant performance, and believes very significant additional investments are necessary to improve safety and reliability. While the plant's capacity factors have been good, the performance indicators have been low when measured against criteria set by the Institute for Nuclear Plant Operation (INPO).

**Summary of Comments Received**: Generally the comments noted that the increasing spending forecasts are of concern and that EN and CGS should work to reduce the costs. As shown in the comments below, no specific reductions were suggested.

- We are "concerned with the proposed $51 million increase. More background should be provided in a clear fashion for BPA's customers .... The CGS budget must undergo the same review and scrutiny applied to other projects and programs. (We) commend BPA on efforts to influence the reduction of the proposed CGS budget."
- "(T)he operating costs of CGS are the most significant upward cost driver in BPA's program levels for 2009. BPA and CGS should continue to work to identify cost reductions without hindering the safe and reliable operation of this plant."
- "While the proposed increases in costs for CGS O&M are significant, we believe these expenditures are necessary. We note EN reduced its original funding request from $65 million to $51 million, and trust EN and BPA will continue to find positive ways to work together."
- "EN and BPA should continue to develop a closer working relationship when it comes to the inclusion of EN costs in the BPA budgeting and rate making processes."

**BPA Response:** BPA has been and will continue to be clear that we are very much concerned with the safe and reliable operation of Columbia Generating Station. Safety and reliability are paramount goals, but it is essential that we meet those goals in the most cost-effective way possible. While BPA has chosen to non-disapprove the 2007, 2008 and now the 2009 budgets we are concerned about the rapid rate of increase in costs for CGS operations from the levels EN management endorsed in 2006. In conjunction with Energy Northwest management, a set of performance indicators has been developed. We are actively tracking these indicators on a quarterly basis. This tracking should help ensure that these major increases in spending actually yield the improvements they are intended to produce. EN management has also proposed to develop a long range plan with significantly increased rigor such that it would provide greater confidence to BPA and others that actual results will be consistent with the plan. We also understand the EN Board has indicated a desire to seek independent counsel to review budget proposals from management. We believe this is an appropriate step and encourage its implementation. We would be interested in working with the Board to see how we could benefit from the counsel of any independent review the Board undertakes. Finally, BPA is considering seeking independent counsel from individuals with significant nuclear plant executive management and operations experience in order to be able to complement our on-site Richland staff's experience. The focus of any contracted additional executive nuclear expertise will be to assure our budget review and oversight authority is executed in a manner that will promote the safe, reliable and cost-effective operation of CGS consistent with the project agreements. We also intend to continue to urge the EN Board to adopt the overarching principle we proposed to the Board last year. As stated below, this principle seeks to provide greater alignment throughout our organizations through focusing on the complementary nature of our missions. That principle is as follows:

> "BPA and ENW are committed to long-term, safe, reliable operation of CGS accomplished at the lowest reasonable cost necessary to achieve those objectives. It is also our objective to integrate CGS with the Federal Columbia River Power System and to achieve optimum utilization of the resources of that system taken as a whole and to achieve efficient and economical operation of that system."

**Decision:** The program levels for CGS O&M and capital remain the same as that originally proposed in the initial IPR.

### B. Corps and Reclamation

**Expense**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 248,173 | 261,600 | 261,600 |

**Capital**

| Original WP-07 (2007-2009 average) | Initial IPR | Final IPR |
|---|---|---|
| 150,301 | 154,950 | 154,950 |

**Columbia River Fish Mitigation Project (Capital)**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 62,425 | 62,425 | 110,000 |

BPA works with U.S. Army Corps of Engineers and the Bureau of Reclamation to implement funding for operations and maintenance (O&M) activities at 31 hydro electric facilities throughout the Northwest, and to ensure implementation of all regionally cost-effective system refurbishments and enhancements to Federal hydro projects. A major asset management planning effort has been conducted as part of the BPA Enterprise Process Improvement Project (EPIP). Major drivers of change affecting Corps and Reclamation O&M include WECC/NERC Compliance requirements, non-routine extraordinary maintenance requirements, and Bi-Op requirements. BPA expects O&M spending to rise at roughly the rate of inflation (except for non-routine extraordinary maintenance activities like the Grand Coulee Dam Third Powerhouse rehabilitation, and the other items mentioned above.)

**Columbia River Fish Mitigation Project (CRFM)** includes the power portion of investment funded by Corps of Engineers appropriations for investment on mitigation efforts for fish and wildlife on the Federal Columbia River dams. BPA becomes obligated to repay the power portion of the costs to the US Treasury at the time the investment is considered completed and placed into service. While the forecast of total investment from FY 2007 through 2011 has not changed significantly, the Corps provided an updated forecast reflecting a change in the expected timing for investment being placed into service, with less than forecast going into service in FY 2007, and considerably more expected in FY 2008 than forecast in the WP-07 rate case.

**Summary of Comments Received:**

- "The FCRPS Hydro Program has a detailed, rigorous and structured asset management program ... easy to follow and understand. The benefits of investment were well presented. We request BPA exercise diligence to identify projects or program areas where costs could be reduced to offset some of the impacts of the proposed asset management initiatives."
- "The ramp up of capital expenditures in FY 2009 is significant ... to catch up with capital improvements that have lagged over the last several years and the reliance on increasingly costly hydro generation equipment .... The agencies should be encouraged to broaden their supplier network so they are not captive to a small number of suppliers."
- "O&M takes a substantial jump. We believe that the agencies should be encouraged to take steps to reduce or eliminate inefficient O&M, rather than just escalating O&M costs by a fixed amount."
- "It is concerning to see FY 2009 O&M increasing $13 million over the original FY09 level and they should be encouraged to continue to manage to the original budgets. We are supportive of capital investments to catch up with hydro system improvements that have lagged over the last several years."
- Re: Corps Cultural Resources Funding at Lake Roosevelt National Recreation Area (LRNRA) – "We are asking for an increase in funding for the protection of our significant cultural heritage, either through stabilization or the excavation of the many archaeological sites affected by dam operations. Funding has been constant since 1995 with no increase for approximately 13 years. Archaeological Surveys have documented the presence of at least 500 cultural resource sites in the LRNRA, most of which are being adversely affected by reservoir operations."

**BPA Response:** BPA recognizes that its customers expect continued collaboration with the Corps and Reclamation to ensure the hydro assets are operated and maintained effectively. Part of this collaboration includes an active ongoing asset planning process that assesses the condition and health of the system and its equipment, evaluates various risk scenarios and their consequences, considers alternatives for achieving reliable generation system performance, and estimates the financial and economic returns for the program in the future. Initial conclusions for the first of many future iterations of this planning process were completed this year and shared with BPA's customers through the IPR. In addition, asset planning helps identify resource needs and investment activities for the coming rate periods -- it takes a long-term view for system sustainability. Three objectives were critical to guiding the asset planning process. They are: 1) low cost power, 2) power reliability and 3) trusted stewardship. Throughout the asset planning effort, the Corps, Reclamation, and BPA were constantly challenging ourselves to satisfy and, to the extent possible, have the results of the proposed plan maximize these objectives.

The increase in O&M costs for FY 2009 are directly related to this asset plan as well as other regulatory requirements, and are attributable to increasing non-routine extraordinary maintenance activities, updated Biological Opinion compliance measures, and new WECC/NERC reliability compliance measures. Critical to the asset plan are budget increases to provide funds for increasing non-routine extraordinary maintenance activities at the generating projects. Failures associated with aging, worn out infrastructure are increasing, causing potential safety problems and operational issues at the plants. If not addressed, these non-routine extraordinary maintenance items will increase risks associated with increased forced outages, reduced generating capability due to units being out of service, reduced system capacity and operational flexibility, and employee safety. Budget increases for WECC/NERC compliance are required to provide resources necessary to ensure compliance with new reliability standards. Additional funding is needed for reliability coordinators, to provide training and perform process analysis, to implement corrective actions and ensure documentation, and to provide data storage. Not meeting the standards increases the risk of a catastrophic system operational event, and WECC/NERC will assess fines and sanctions for being out of compliance with the standards. Increased budgets for BiOp activities are necessary to address aging infrastructure needs, particularly associated with hatcheries. Not addressing these BiOp requirements risks non-compliance with the BiOp and associated court actions.

Funding levels for Cultural Resource activities across the FCRPS were derived from the System Operations Review (SOR) and agreed to by the Corps, Reclamation, BPA, and the tribes. The term of the agreed upon funding was for 15 years, which is up in 2012. Changes in funding levels for Cultural Resources will be addressed during development of a new agreement for funding which will take effect in 2012, after the 15 year original term is completed.

BPA and its partner agencies will continue to monitor the condition of the generation assets to ensure the value of the system is sustained at an appropriate level of risk. Nearly 25 percent of the power train equipment at plants critical to the system is currently in Marginal or Poor condition, according to hydroAMP, our equipment condition rating system. The lost generation risk (with no action) is estimated at $871 million, which improves to $479 million by 2016 with the implementation of this asset plan. Also, overall equipment condition improves by 7 percent, with the largest gains at the highest risk plants of Grand Coulee, Chief Joseph and McNary.

Clearly, unanticipated needs will arise as we move forward requiring continuous management and being flexible with regard to decisions and direction suggested by the plan. BPA's Federal Hydro staff, working with the Corps and Reclamation, will scrutinize all resource needs, both capital investment projects and operation and maintenance funding to ensure the lowest cost to ratepayers while preserving generation reliability and satisfying our stewardship responsibilities for the river system under our care.

**Decisions:** No changes are being made to Corps and Reclamation O&M, including for Corps and Reclamation Cultural Resources activities, or for hydro capital investment. The revised CRFM plant-in-service schedule provided by the Corps during this IPR process will be adopted in the final IPR forecasts.

### C. Long-term Generation Program

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 25,751 | 31,613 | 31,522 |

This program consists of BPA’s long-term acquisition contracts for output from generating resources, such as Cowlitz Falls, Billing Credits Generation, Wauna, Elwah Dam, Idaho Falls Bulb Turbine, and Clearwater Hatchery Generation. Most of the expenses associated with the long-term generating projects are based on energy production at the generating units, and therefore are offset by revenues. There is little opportunity for improvement because prices are fixed by contract.

**Summary of Comments Received:**
None

**BPA Decision:** No comments were received on this program. The primary change from the original WP-07 rate proposal to the IPR forecast is that the WP-07 rate proposal did not include Idaho Falls Bulb Turbine as a generating resource, since there was not a signed contract in place for the FY 2007-2009 period at the time of that proposal. The increase since the original WP-07 proposal reflects the cost associated with that resource. The amount of generation produced by this resource is included in the Load Resource study in the WP-07 Supplemental rate proposal. It is appropriate to include the cost of the resource as well. An error was discovered in the calculation of the maximum cost of this resource subsequent to the last FY 2009 IPR workshop. Correction of this error results in a $90.7 thousand decrease to the cost of this resource. This correction is being adopted and is incorporated into the Final IPR spending level for Long-term Generation. No other changes are being made to the original IPR forecast.

### D. Renewable Resources

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 41,917 | 43,955 | 43,955 |

BPA’s goal for renewable resources is to ensure the development of our share of cost-effective regional renewable resources at the least possible cost to BPA ratepayers.

BPA's share will be based on the regional load growth (about 40 percent) of its Public Utility customers. BPA will cover its share through power acquired by BPA from renewable resources to serve its Public customers and/or renewable resources acquired by Publics with financial assistance by BPA.

Two changes from the original WP-07 rate proposal are reflected in the IPR proposed spending level. First, $9.6 million is included for power acquired from the Klondike III wind project, which was not contemplated in the 2007 rate case. The costs incurred by this project are recovered through revenues generated from the sale of the project's generation and environmental attributes to BPA's Public Utility customers. Second, due to recent state legislative enactment of renewable portfolio standards in Washington and Oregon, many Publics are meeting the Council's forecasted renewable development without BPA facilitation spending. In light of this advancement, the FY 2009 Facilitation spending level was reduced from $13 million to $2.5 million. (An additional $3 million is included for Green Energy Premiums from Environmentally Preferred Power (EPP) and Renewable Energy Certificate (REC) sales transferred to Technology Innovation (TI) to fund renewable research projects. See Agency Services below.)

**Summary of Comments Received:**

- "Reducing BPA's renewable energy budget at this time is the wrong direction. The proposed expenditure of $2.5 million (for facilitation) is woefully inadequate to respond to customer's needs for new renewable resources and to assist the region in preparing for climate change regulation."
- "The reduction in facilitation services and programs is shortsighted."
- "BPA should be proactive in helping its customers take advantage of federal renewable credits ...."
- "(We are) concerned that the renewable-resources budget has been cut so drastically that the agency will be unable to assist its customers in acquiring these resources at the very time the agency's customers will be required under state law to acquire them."
- "With the growing importance of climate and renewable energy policy, BPA needs to dedicate appropriate resources to this area."
- "We commend BPA for acknowledging the region's successes in developing renewable resources by reducing its facilitation budget .... We urge BPA to continue to reflect the region's progress in renewable resources, and other areas, by adjusting its program budgets accordingly."
- "(We) concur that BPA should reduce the proposed renewables budget. There has been much progress in the region in developing renewables and this proposed change acknowledges that progress."
- "BPA should be holding the line on conservation and renewables spending in anticipation of state conservation and renewable portfolio standards .... Utilities will be continuing their recent progress in developing renewable resources and the need for BPA facilitation is likely to be much less than it has been historically."

**BPA Response:** BPA has set the renewable facilitation proposed spending at the level necessary to meet its renewable resource policy goal. BPA's goal is to ensure that BPA and public power stay on track to purchase public power's share of Council forecasted renewables. BPA will meet that goal at the least possible cost to BPA ratepayers. BPA intends to adjust its facilitation spending each rate period based on its progress in meeting that goal. BPA believes its customers are doing a good job acquiring renewable resources to meet the targets established in the Council's Fifth Power Plan and the targets established under State Renewable Portfolio standards. The large amount of renewable resources under development in the region suggests there is less need for BPA to spend facilitation dollars to encourage their development.

A number of comments equated dollars included in the renewable facilitation program with BPA support for renewable resources. BPA believes its support for renewable resources is best measured in the accomplishment of its targets. BPA expects to offer a Tier 2 vintage rate based on renewable resources that will assist individual customers in meeting their individual renewable targets under State Renewable Portfolio standards.

**Decision:** BPA will make no change to the Renewable Resources program level.

### E. Conservation

**Expense**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 70,347 | 84,526 | 80,526 |

**Capital**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 32,000 | 42,000 | 32,000 |

BPA's conservation program (expense and capital) has a goal of delivering 52 aMW of conservation savings per year (net of any naturally occurring conservation) during the FY 2007-2009 period, compared to an average of 44 aMW per year over the FY 2002-2006 rate period. Increases are primarily due to forecasting additional spending for acquisition, support for regional delivery infrastructure required to achieve accelerated conservation targets, and load management work related to BPA's 2008 Resource Plan.

**Summary of Comments received**:

- "Bonneville needs to create the incentives and provide the support to help its customers succeed .... Our concern is that there is no increase in BPA staff to ensure the effective spending of this increased budget."
- "It is vital that funding for 2009 conservation programs be increased .... If funding is held constant in 2009, we risk losing cost effective energy savings. Further, maintaining spending and 2008 levels sends the wrong message to utilities, Congress and all stakeholders on the value of energy efficiency."
- "I am extremely disappointed that there is no substantive increase in the budget for energy efficiency. The region and the planet are undergoing the greatest environmental challenge ever faced, and BPA refuses to take advantage of clear and cost-effective efficiency opportunities with any sense of priority. There is no excuse for the inaction on energy efficiency in the proposed budget, and it should be corrected before being finalized."

- "BPA's proposed increase in conservation funding does not consider state renewable portfolio standards that place responsibility for energy efficiency on individual utilities. BPA should begin to ratchet down its program, rather than expand its budget."
- "A flat conservation budget reflects a failure to recognize the clear economic and environmental benefits of energy efficiency .... Now is the time for Bonneville to begin to ramp up this program in anticipation of the higher efficiency targets that will be set in the 6th Power Plan."
- "We would encourage BPA to adopt a more flexible budget approach that allows for more innovation and reaction to opportunity for more robust FY 2009 efficiency gains."
- "(We do) not support the proposed increase in conservation spending above WP-07 levels."
- "Because the region has demonstrated its ability to achieve conservation under current levels of BPA spending, we question the proposals for increases above the previously set budget for 2009."
- "Specificity in the nature of some of these costs is needed to provide clarity to the programs ratepayers are funding. For example, the difference between "conservation" and "regional energy efficiency"... is not evident. With BPA expecting these costs to increase, customers need greater clarity as to the differences and the reasons BPA believes it is necessary for these budgets to increase."
- "BPA should be holding the line on conservation and renewables spending in anticipation of state conservation and renewable portfolio standards .... Having BPA charge its customers a half mil for this program, that those customers must spend time and money justifying their efforts in this area just to get this credited back would seem to be a redundant, expensive waste of effort, resources and time."
- "BPA needs to set budgets for conservation taking into account that customers are responding to these signals. This should result in a decrease in BPA conservation programs and thus a reduction in costs in FY 2009 from the original budget."

**BPA Response:** The Agency agrees that conservation will continue to be a priority in the future, and believes that the FY 2009 proposed spending level for Energy Efficiency is structured to best position the region to meet the need for additional conservation capability.

BPA believes there needs to be a conversation with customers and other stakeholders regarding what role BPA will play in energy efficiency in the post-2011 period. Given the workload for interested parties and BPA associated with developing new long-term contracts, we don't believe this energy efficiency question can be effectively engaged at this time. BPA is committed to engaging the region on this question following the beginning of the next calendar year. It seems likely, however, that the aMW targets for energy efficiency acquisitions will be increasing in the coming years. For this reason, we believe providing funding for some "ground-plowing" activities is important regardless of the direction BPA ultimately takes in energy efficiency. We believe, for example, there is a need for load-management scoping and planning activities due to growing forecasted regional capacity deficits and the movement toward long-term contracts requiring that BPA augment its system for capacity, as necessary. Revisions to the regional reporting system, trade ally development, planning of marketing strategies and evaluation of existing programs will provide a firmer foundation supporting BPA's commitment to collaboratively working with public power to assure its share of the regional energy efficiency targets are accomplished. The additional spending in the area of Low-Income Weatherization reflects the fact that spending did not occur at the expected rate in the first two years of the rate period. Therefore, the $800,000 added to the planned FY 2009 budget reflects the timing for the funds to be spent and is not an overall increase in spending.

**Decisions**: After close examination of the proposed Energy Efficiency program level, BPA has identified two reductions which are appropriate and will not impact energy efficiency goals in FY 2010 and beyond. The first is to reduce the proposed capital spending from $42 million to $32 million for FY 2009. Capital spending in this rate period to date has been below historical trends. Reducing this line item should not negatively affect the ability of BPA and the region to achieve 2009 energy efficiency goals. BPA has also reduced the amount of the rate credit for 2009 from $36 million to $32 million to reflect the fact that IOUs are no longer eligible for rate credit funding.

### F. Fish and Wildlife Direct Program

**Expense**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 173,353 | 229,439 | 229,439 |

**Capital**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 36,000 | 50,000 | 50,000 |

BPA’s Direct Fish and Wildlife Program manages projects to meet BPA’s mitigation objectives under the Northwest Power Act, in a manner consistent with the Northwest Power and Conservation Council’s (Council’s) Fish and Wildlife Program, as well as BPA’s Endangered Species Act (ESA) requirements under biological opinions from the U.S. Fish and Wildlife Service and National Oceanic and Atmospheric Administration (NOAA) Fisheries.

The primary drivers of change are ESA requirements pursuant to new Biological Opinions (e.g., the May 5, 2008 FCRPS Biological Opinion) (BiOp), requiring increased spending for habitat restoration, hatchery reform, and research, monitoring and evaluation. In addition, BPA has executed the 2008 Columbia Basin Fish Accords, which are agreements with States and Tribes regarding implementation of fish and wildlife projects to mitigate for effects of the FCRPS, including requirements under ESA. The Fish Accords include expected costs necessary for implementing actions to support the BiOp, and other FCRPS mitigation. The Fish Accords benefit the agency and the region in the following ways:

- They help mitigate the impacts of the FCRPS, particularly on ESA-listed species within projects that are expected to provide significant and measurable benefits.
- They reinforce partnerships with key players ending years of divisiveness.
- They provide funding stability, leading to more certainty of implementation and stable rates.

The Fish Accords reinforce an all-H approach by focusing on multiple strategies to produce biological benefits that are cost-effective and satisfy BPA's legal obligations under ESA and the Power Act. Increased costs are partially offset by 4(h)(10)(C) credits, which, in essence, reimburse BPA for the portion of costs that are attributable to non-power purposes of the FCRPS.

**Summary of Comments Received:**

- Washington Department of Fish and Wildlife (WDFW) considers certain identified projects as either critical and essential projects within the FY 2008-2009 funding decision, or necessary projects to begin to implement the recent BiOp in FY 2009. "We are aware there may be funding available from Fish and Wildlife Program expense "carryover" from FY 2002-2006 along with unspent FY 2007-2008 funds. In your review, we ask you to consider exploring whether the needs we identified may be met with carryover and planning dollars and therefore could be addressed without necessarily impacting the FY 2009 power costs."
- "Bonneville should budget sufficient dollars to fund the unmet needs identified by the Council in its FY 2007-2009 recommendations. BPA arbitrarily set its annual budget for this time period at $143 million, despite the fact it was much less than the $150 million originally proposed for FY 2002-2006."
- "We ... urge you to resolve the growing disparity between resident and anadromous fish mitigation funding. We are concerned that BPA's proposed funding schedule deviates from the Fish and Wildlife Program goal for Anadromous Fish, Resident Fish, and Wildlife categories (known as the 70:15:15 allocation) .... A recent estimate provided by CBFWA indicates that BPA's proposed allocation would allocate 75% for anadromous fish projects, 11% for resident fish projects, and 13% for wildlife projects .... (C)urrent projections indicate that resident fish and wildlife projects will not keep pace with anadromous fish restoration actions. BPA should revise these resident fish and wildlife mitigation requirements when calculating the Program funding level for the 2009 rate case. This disparity could be resolved ... by scheduling 7% more than the $200 million in costs proposed for FY 2009."
- "We strongly support BPA's proposal to increase its fish and wildlife funding to fully implement the MOA (with States and Tribes) .... We expect the IPR close-out letter to include expense funding for the MOA with CRITFC, the Yakama Nation, and the Umatilla and Warm Springs Tribes of approximately $35.5 million in FY 2008 and $49.4 million in FY 2009; the capital budget will be approximately $10.6 million capital in FY 2008 and $20 million capital in FY 2009."

- "BPA should carefully review this proposed ($38 million) increase and look for duplicate efforts or items that are not required. Further, these initiatives need to be results oriented."
- "Questions remain as to how the Council Program, MOAs, a new BiOp, and other elements of BPA's fish and wildlife budget will be integrated into an effective program. These uncertainties should not be an avenue for additional budget increases beyond those proposed for FY 2009."
- "BPA should work to ensure there are no duplicative efforts or double funding of projects. The litmus test for new elements of the fish and wildlife program is that they complement existing fish and wildlife projects. "
- "BPA should limit fish and wildlife spending to projects affected by BPA's operations of the FBS. There are many existing and proposed projects in areas that have little relation to BPA operations."
- "The program budgets should be fixed, regardless of whether or not the program has spent all of the allocated dollars in the previous year."
- "The funding should be seen as comprehensive for both fish and wildlife and the proposed budget should not increase beyond its current limit."
- "We support a long term capped budget for the fish and wildlife direct program and believe that this is important for all parties."
- "We do request that BPA perform an analysis of whether it is appropriate to apply the inflation adjustment to the entire direct program, or only that portion of the program that is truly subject to inflation."
- "Most of the FY 2009 increase is targeted to fund projects identified in the tribal MOAs and elements of the BiOp. While (we do) not dispute the value of these projects, much of the funding will not go toward making the BiOp sufficient to restore endangered salmon and steelhead nor satisfy BPA's obligations in this arena."

**BPA Response:** BPA's Fish and Wildlife Program budget encompasses both BPA's Northwest Power Act and ESA compliance obligations. The Program is carried out in partnership with the Council. ESA-related project commitments benefiting listed salmon and steelhead are also coordinated with NOAA Fisheries. BPA's program is implemented primarily through BPA funding of several hundred individual projects and contracts intended to mitigate for the effects of the FCRPS on fish and wildlife.

In the IPR workshops on Fish and Wildlife Program funding for FY 2009, BPA proposed a very significant upward spending level adjustment for both the expense and capital portions of the Program, from $143 million and $36 million, respectively, to $200 million and $50 million. These proposed spending levels reflect the funding increases needed in FY 2009 for implementing both the new FCRPS BiOp and the Columbia Basin Fish Accords, without reducing funding for the other non-BiOp and/or non-Accord elements of the Program. While the magnitude of these funding increases is unprecedented in nature, BPA believes these increases are critical to both ensure its ability to deliver on commitments reflected in the Biop and Accords, and to move the region away from years of divisiveness and litigation under the ESA toward support for and implementation of an all-H (hydro, habitat, hatchery and harvest) approach for ESA compliance and recovering

ESA-listed salmon and steelhead. The actions funded via these commitments are expected to produce targeted biological benefits to specific population groups of ESA-listed stocks. These commitments themselves make these actions more reasonably certain to occur and demonstrate that the entities signing the Accords are committed to and accountable for achieving identified biological benefits and that projects which haven't previously undergone independent science review will be reviewed prior to implementation, consistent with the Power Act. BPA acknowledges that it has proposed this very significant Program spending increase ahead of developing detailed "statements of work" for these new project commitments. To that end, BPA is committed to ensuring adequate independent science review and project scoping, including appropriate adjustments as necessary and agreed-upon with Accord signatories.

Comments on BPA's proposed spending increases varied significantly, with some suggesting that BPA fund additional and/or different projects, and others raising concerns about adequate science review and more general program management issues. With respect to suggestions to fund additional projects, some of these suggestions have been made previously, and BPA has responded to them previously, such as within its FY 2007-2009 funding decision and a December 31, 2007 response letter to the Columbia Basin Fish and Wildlife Authority. As far as new work not previously suggested, BPA believes that while there will always be an interest in funding for additional new projects, there is substantial opportunity and flexibility within the existing Program and its base $143 million spending level to fund appropriate additional work by rededicating funding as some projects reach their natural end and by leveraging potential efficiency gains from upcoming Council-led reviews of parts of the current program (such as wildlife and monitoring/evaluation). In addition, the Council's new High Level Indicators initiative has the potential to drive reform of the region's research, monitoring and evaluation efforts, thereby creating further spending flexibilities.

BPA's customer representatives provided several suggestions relating to additional spending increases beyond those proposed for FY 2009; science review; economic review; and inflation. These suggestions and accompanying responses are as follows:

- One suggestion was that BPA look for the potential to reduce funding of other projects where there are duplicative efforts and/or a lack of a clear FCRPS mitigation nexus; BPA believes such an assessment is appropriate and should logically occur as part of the Council's upcoming project review initiative.
- BPA customers asserted that outside the BiOp and Accord commitments, unspent funds should not be carried forward nor made available for funding projects in the future. As part of its FY 2007-2009 project funding decision BPA made a decision to carryover $8.8 million in unspent funding from the previous rate period, so as to not create a "use-it-or-lose-it" incentive. As for FY 2010-2011, as it relates to projects outside the BiOp/Accords, BPA will make a decision on how to handle unspent funds as part of the development of a budget management plan for overall Program budget management. BPA expects to develop this plan during the summer of 2008 and will provide an opportunity for Council, customer and Program stakeholder input.

- In terms of science review, BPA is committed to ensuring adequate independent science review consistent with the intent of the Science Review amendment to the Power Act.
- BPA may also suggest, as noted by BPA's customers' comments, that the Council utilize the Independent Economic Advisory Board for cost-effectiveness assessments as appropriate.
- Regarding inflation, BPA's FY 2009 proposed spending level does not reflect an inflation adjustment. However, BPA has proposed an annual adjustment of 2.5 percent per year starting in FY 2010. BPA agrees with the customer suggestion that the addition of an annual inflation adjustment provides, in part, a rationale for an overall budget commitment or cap. Such a commitment, with the addition of the inflation adjustment, could provide substantial flexibilities for future project funding decisions within an overall set budget through applying the inflation adjustment where necessary and redirecting it elsewhere when it isn't needed for a particular project.
- Finally, BPA is also committed to working with its customer representatives and other program stakeholders to ensure that its daunting implementation challenges relating to the ramp-up of the Program occur in the most efficient, effective and biological-results-oriented manner.

**Decision:** No change. Taking into account all the drivers that led to BPA's initial FY 2009 budget proposal in the IPR, and the range of comments received, BPA believes that it is appropriate to increase the Fish and Wildlife Program expense and capital budgets to the $200 million and $50 million levels, respectively, as proposed in the initial IPR numbers for FY 2009. These increases will: 1) make good on commitments/actions reflected in the new BiOp and Fish Accords; while 2) not reducing funding to other projects which provide important mitigation benefits relative to BPA's Power Act obligations. BPA notes that, in addition, there are sufficient tools and flexibilities within the existing Program to redirect funding to other projects, assuming support for doing so exists among program stakeholders. BPA acknowledges, however, that there are many new budget management complexities as well as policies that will need to be developed, and important unanswered questions that still need to be addressed given the new Biological Opinion and Fish Accords and the related significant Program increase in FY 2009. Over the summer of 2008, BPA will continue to develop an overall Fish and Wildlife Program budget management plan in coordination with the region, with opportunity for input and comment, to address these questions, issues and policies.

**G. US Fish and Wildlife Service: Lower Snake River Compensation Plan**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 19,600 | 19,600 | 19,600 |

This program funds 11 hatcheries and 15 satellite facilities owned by the Fish and Wildlife Service (FWS), and operated by the FWS and fisheries agencies of states of Oregon, Washington, Idaho, Nez Perce, Shoshone-Bannock and Confederated Tribes of the Umatilla. This program is legislatively mandated to mitigate for the existence and operation of the four Lower Snake River Hydroelectric dams constructed in the 1970's.

**Comment received:**

- "I was pleased to learn that the U.S. Fish and Wildlife Service and BPA secured consensus to a budget that provides funding for the LSRCP hatchery and monitoring an evaluation operations, including hatchery and M&E programs operated by Washington Department of Fish and Wildlife. The proposed budget aligns with the congressionally mandated commitment to mitigate for the loss of fishing opportunity resulting from construction of the four Lower Snake dams. . . . WDFW shares these goals and supports the modest annual rate increase to cover anticipated costs."

**Decision:** No change

### H. Internal Operations (Including Pensions and Post-Retirement Benefits)

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 126,941 | 140,307 | 136,295 |

Internal Operations includes Agency Services allocated to Power Services, Agency Services costs direct-charged to Power Services, as well as the internal operating costs of Power Services itself.

**Summary of Comments Received:**

- "BPA's internal costs are increasing dramatically overall, despite savings achieved in some areas. BPA should set reasonable caps for growth in internal operating costs, no higher than the annual rate of inflation, and then live within those caps."
- "BPA's forecast internal power operations costs for FY 2009 are escalating significantly .... For example, General Counsel ..., Finance ..., and Technology Innovation .... BPA could limit the net escalation in its internal operating costs to the rate of inflation. If the agency wants to add new functions, it should identify offsetting savings in other functions."
- "(We are) very concerned with the rate at which internal costs are increasing. . . BPA should look at these costs and find ways to reduce them to more acceptable levels (inflation or less): Chief Risk Officer, Technology Innovation, Internal Audit, Strategic Planning, Strategy Integration, General Counsel, Workplace Services
- "BPA has not justified the proposed 14% increase in internal power costs."

**BPA Response:** Internal costs charged to power have been held virtually flat since FY 2001. While there is an increase proposed in the IPR, it results in costs that are still well below where they would have been had they increased at the rate of inflation since FY 2001. We believe holding these costs flat is no longer sustainable and that increases must occur. However, BPA has taken seriously the comments on the significant increases to internal operations costs.

**Decision:** The Power internal operating costs and total Agency Services costs will reflect a three-percent reduction from the levels included in the IPR. The actual distribution and means of meeting that three percent reduction will be determined by Executive Management in order to achieve this lower level of spending.

Below, we have outlined the drivers behind spending increases in programs that were specifically identified in customer comments.

**(a) Chief Risk Officer:**

| Rate Case | Initial IPR | Final IPR |
|---|---|---|
| 5,136 | 5,871 | 5,871 |

The key responsibilities of Risk Management include: facilitating a risk-based approach to strategic planning in which BPA's tolerance for specific risks and overall risk management capability are key inputs to strategy development and execution plan; coordinating a robust and sustained Enterprise Risk Management (ERM) program to identify and appropriately address the broad range of risks to achievement of the agency's strategic objectives; monitoring and reporting on BPA's full range of risks, including commodity transacting risks; mitigating BPA's credit exposure in the event of counter-party default; and implementing a Business Continuity Management Program, including Emergency Management and Continuity of Operations planning. The primary driver of increase for FY 2009 spending estimates is the incorporation of funds for the Business Continuity program, including contractor support.

**(b) Technology Confirmation / Innovation:**

| Rate Case | Initial IPR | Final IPR |
|---|---|---|
| 3,373 | 9,916 | 9,916 |

The Technology Innovation program focuses on actions that have substantial value for BPA's ratepayers. The program is guided by a set of technology roadmaps specifically developed to narrow the focus of technology innovation to solving business challenges BPA is facing. The roadmaps were created with internal and external expert input, and address major technology issues in transmission, hydro, energy efficiency, renewable energy, and security areas. They provide robust, public guidance to BPA's technology innovation program and to our potential partners – utilities, EPRI, and others.

BPA's research spending was drastically reduced in the late 1990's. Beginning in 2000 some growth occurred in transmission, driven by needs to advance critical research related to reliability. As a result, funding rose to an estimated $3 million by FY 2005. Similarly, a few special-exception projects were planned on the power side, including: energy efficiency projects related to the EnergyWeb concept; Hydro operations projects relating to specific trials of new turbine runners; and projects tied to a growing realization of issues related to renewable energy. The Research and Development (R&D) spending for the power side also grew to around $3 million in

2005. Together, the estimated FY 2005 spending forecast of $6 million accounted for less than 2/10ths of 1 percent of BPA revenues.

BPA management benchmarked it's expenditures against the utility industry as a whole, and against other industries. BPA also looked ahead at the challenges facing the Federal Columbia River Power System, including transmission reliability issues, the need for future energy efficiency technologies and renewable energy, and the impacts of climate change.

BPA concluded that its technology innovation investment was insufficient considering the business challenges it faces. The benchmarking revealed that the US utility industry in general was far behind nearly every other industry in the level of expenditures for R&D. More importantly, BPA executives saw a coming set of challenges that could not be effectively dealt with unless BPA had an organized, focused, strategically directed technology innovation program. Ad hoc research projects taken up off-the-cuff, weren't going to address these challenges.

The 2005 Power Function Review and the 2006 Programs in Review tipped out BPA's conclusion that a more appropriate spending level for R&D was 1/2 of 1 percent of revenues.

In order to facilitate and manage this ramp-up to a more appropriate agency spending level, the Technology Innovation central office function was decentralized in FY 2007. In the beginning funds provided for just the salaries and incidental costs of start-up staff. Funds were then assumed to grow at a gradual pace, leading to the targeted level by about FY 2011. This IPR proposal moves the targeted funding to FY 2012. The $6 million in the balance of the agency was assumed to continue to be invested as in the past.

BPA created the Technology Confirmation/Innovation Council as a cross-agency team of executives and experts that guide the formation and operation of the Technology Innovation program. This group's deliberations have guided the transformation from a decentralized model to a centralized model in which R&D spending, expenditures, and project progress can be better managed.

This change occurred between FY 2007 and FY 2008. Hence, the $1.6 million in FY 2007 represents the central office function before consolidation, and the $9.6 million represents the combination of $6 million formerly reflected in power ($3 million) and transmission ($3 million) and the growth in centralized funds along the ramp up to 1/2 of 1 percent of revenues. The total agency spending estimates as described in the IPR is the same as that used for the currently established rates.

BPA believes that the Technology Innovation program is on the right track and that the growth to the target level of investment should continue as reflected in the proposal. The program is addressing critical issues facing BPA and the Federal Columbia River Power System.

### (c) Internal Audit:

| Rate Case | Initial IPR | Final IPR |
|---|---|---|
| 1,930 | 2,384 | 2,384 |

Internal Audit supports governance and serves BPA managers through audits, reviews, analyses, and other services. A key driver of change is accelerated succession coverage with pending retirements of key staff. Internal Audit has also responded to new and/or expanded governance, risk management, and compliance activities that require more, regularly-scheduled audit support. This includes annual support for OMB Circular A-123 assessment of internal control over financial reporting, a Federal requirement that parallels that of Sarbanes-Oxley Sec. 404 for publicly traded companies.

### (d) Strategic Planning and Strategy Integration:

| | Rate Case | Initial IPR | Final IPR |
|---|---|---|---|
| Corporate Strategy | 340 | 303 | 303 |
| Strategic Planning | 1,771 | 1,913 | 1,913 |
| Strategy Integration | 7,510 | 7,604 | 7,604 |

The Agency Services Corporate Strategy group combines Strategic Planning and Strategy Integration. Corporate Strategy is charged with the following activities:

- Industry intelligence/market fundamentals
- Coordinated infrastructure planning & analytical tools/modeling, scenario analysis and strategic options
- ColumbiaGrid funding and functional agreements (planning & expansion, reliability and staffing, OASIS)
- Greenhouse gas policy analysis
- Development of greenhouse gas strategy
- Wind integration coordinated operations planning
- Multi-year strategic objectives, initiatives, and performance targets
- Agency capital project valuation and approval process
- Agency-wide performance management system

It is true that the expenditures for the agency's Corporate Strategy function are showing increases over the period covered by the IPR. There are two factors driving these increases:

First, this includes BPA’s support for ColumbiaGrid. The ColumbiaGrid approach to one-utility planning and operations is a building block approach. Since its creation in late 2006, ColumbiaGrid has been building its basic capability by establishing a Board of Directors and an executive team, and creating the region's only independent regional transmission planning capability. Funds included in FY 2009 allow for the completion for ColumbiaGrid design work in the areas of transmission service and operations, and for the potential implementation by ColumbiaGrid of resulting proposals in those areas.

Second, there are fundamental structural changes in the operating environment of the utility industry that are only beginning to unfold. These include dramatic increases in the need for infrastructure investment, sharp increases in infrastructure and fossil fuel costs, aggressive state renewable portfolio standards (RPS), dramatic increases in wind generation, and considerable uncertainty around greenhouse gas legislative actions. These changes will have dramatic effects on BPA's operating and business environment and will affect both the transmission and power services arms of BPA and, ultimately, BPA's customers. The proposed spending reflects BPA strengthening its ability to anticipate, systematically analyze, and manage these changes with least-cost impacts to regional consumers, while maintaining the reliable operation of the FCRPS. For example, BPA's efforts to solve highly complex wind integration challenges will be an important determinant of the region's success in meeting state RPS at least cost. These solutions require a thorough, rigorous, coordinated cross-agency technical and policy analysis that will be led by the Corporate Strategy function.

**(e) General Counsel:**

| Rate Case | Initial IPR | Final IPR |
|---|---|---|
| 9,014 | 9,514 | 9,514 |

General Counsel supports BPA programs through legal advice and representation. Major activities include: (1) Advice and risk assessment, negotiation and alternative dispute resolution; (2) Advice concerning BPA transmission policies and transmission tariffs, contracts and rates; (3) Advice concerning BPA power policies, contracts and rates; (4) Agency representation in all areas of litigation before the courts or administrative and regulatory proceedings covering: power marketing, contracts, rates, energy efficiency, resource acquisition, renewable resource policy matters, federal projects, and nonfederal projects, including Energy Northwest and BPA's statutory and contractual responsibilities with regard to the provision of transmission service; (5) Advice and legal representation in environmental issues and policies including BPA's fish and wildlife obligations under various acts; and (6) Drafting and negotiating financial instruments including documents related to Energy Northwest and Treasury financing.

The primary drivers of increases are the increased need for legal services in transmission due to increased investments and Transmission Service Agreements, resumption of the Residential Exchange with attendant legal review, increases in Fish and Wildlife programs, new reliability standards, and compliance requirements – NERC, FERC, WECC filings, review and interpretation of new mandates and regulations, State law research and opinions critical to BPA and its customers and stakeholders.

**(f) Internal Business Services (IBS):**

| | Rate Case | Initial IPR | Final IPR |
|---|---|---|---|
| Internal Business Services | 576 | 576 | 576 |
| Safety | 2,386 | 2,314 | 2,314 |
| Human Capital Management | 16,472 | 16,228 | 16,228 |
| Supply Chain Services | 16,987 | 18,315 | 18,315 |
| Workplace Services | 26,813 | 32,508 | 32,508 |
| Information Technology | 58,313 | 58,313 | 58,313 |

IBS is comprised of multiple organizations that provide essential infrastructure functions in support of the effective operations for the Agency. The "rate case" values in the table above reflect an effort to create spending levels that tied to both the Power and Transmission rate cases and that incorporate the impacts of reorganizations made up to that time. Looking at just the original FY 2007-2009 Power Rate Case, the overall spending levels for Internal Business Services will be managed to the levels identified in the WP-07 Power rate case, with exceptions in Supply Chain and Workplace Services. The original spending levels included aggressive cost management associated with several process improvement projects in Information technology, Human Capital Management and Supply Chain.

- **Supply Chain**: BPA is forecasting an increase in the FY 2009 spending for Supply Chain Services relative to the original rate case level for FY 2009 in order to support the increased programs for Transmission capital and expense programs, for Fish and Wildlife BiOp Remand and Long Term Agreements, for Research and Development; and implementation of Lease Financing agreements. These programs require new Supply Chain Services support that was not previously included in the original rate case spending level for FY 2009. However, the revised spending level for FY 2009 includes offsetting reductions due to Supply Chain process improvement efficiencies of $200,000 in FY 2009.

- **Workplace Services**: Workplace Services consists of facilities (HQ and Ross O&M and non-electric facilities including field office facilities), leases, space management, office services, printing and mail services. The revised FY 2009 spending level for Workplace Services is consistent with the original FY 2009 level assumed in the original rate case forecast with the exception of the program to address the backlog of deferred maintenance on its non-electric facilities. Over the past 10 years (or more), maintenance on facilities that are essential in delivering transmission services has been deferred, creating a backlog of work that now needs to be addressed. Condition assessments of these facilities have been performed and have uncovered life safety and facility reliability issues that need to be addressed during the upcoming rate case period. As these are Transmission assets, the funding increase associated with the implementation of this program does not impact Power costs.

- **Information Technology** (IT): IT expense spending has remained flat since FY 2006 and will again for FY 2009 consistent with the spending level assumed in the original rate case for FY 2009. IT has been able to keep spending flat (even with absorbing inflation cost) due to EPIP savings achieved through improved contract management, software title reductions, demand management, and service delivery. Expense savings could have been even higher had business demand for IT services not increased dramatically across the agency.

- **Human Capital Management (HCM):** The FY 2009 spending level for HCM has been revised down slightly from the original WP-07 rate case forecast level for FY 2009. HCM has achieved its EPIP efficiencies and its proposed spending level reflects the implementation of HCM services via a new delivery model that focuses on business outcomes, sharpens delivery via expert services, and relies on the deployment of automation tools to manage workflow.

- **Safety:** The FY 2009 spending level for Safety has been revised down by three percent relative to the original WP-07 rate case level to reflect lower than expected contract costs.

**(g) Finance:**

| Rate Case | Initial IPR | Final IPR |
|---|---|---|
| 13,782 | 15,224 | 15,224 |

BPA recognizes the concerns expressed in Joint Public Power comments that BPA's internal operating costs, including Finance costs, are increasing significantly. Much of the increase in Finance spending estimates since FY 2007 has been driven by the reestablishment of the Residential Exchange Program as a result of the recent 9th Circuit Court decisions. ($2 million and $1.1 million were included in the FY 2008 spending estimates and the FY 2009 initial IPR budget, respectively.)

Without the Residential Exchange Program administration costs, the FY 2009 Finance spending level has increased 5.9 percent per year from FY 2007 actuals and 2.8 percent from the FY 2008 spending estimates. During this period, Finance's workload has increased due to accelerated deadlines for the year-end audit, Federal financial reporting, and the Annual Report; the implementation of OMB Circular A-123, Appendix A - the Federal equivalent of Sarbanes-Oxley; the execution and administration of the Lease Financing program in support of BPA's capital program; and negotiation and implementation of new agreements with the U.S. Treasury for borrowing and investing. This increased workload was partially offset by efficiencies, resulting in a small net increase in staffing resources (the equivalent of about 2 FTE). The net result is that the IPR spending level for FY 2009 is about $300 thousand or two percent higher than the spending level included in current Power rates. The Residential Exchange Program, the increasing scale of the Lease Financing program, and the need to restructure financial data to accommodate the implementation of tiered power rates are the primary drivers for Finance spending over the next several years.

**Rate Case Decisions:**
The following section provides information on areas for which the costs will be determined in the Final WP-07 Supplemental Rate Proposal. They have been included in the IPR to provide an opportunity for participants to understand the basis for these costs.

### I. Power Purchases, including monetized benefits to DSIs

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 292,210 | 316,454 | *316,454 |

*The actual amount will be determined in the Final Rate Proposal.

Changes from the WP-07 Rate Case to the Supplemental Proposal include a decrease in the monetized benefits to DSIs from $59 million to $55 million, and increases in the power purchase forecasts due to the firm load deficit in the supplemental rate case being higher (354 aMW vs. 270 aMW) than the deficit in the WP-07 case. A reduction in the expected price of power partially offsets this increase.

**Summary of Comments Received:**
- "BPA continues to provide payments to the DSI's. These subsidies which we understand are $59 million per year are not required under the NWPA post 2001 and should cease."

**BPA Response:** The $59 million identified as monetized benefits to DSIs has been reduced to $55 million for FY 2009. This amount is available to DSIs under an existing contract.

**Decision:** BPA will assume $55 million monetized benefits to DSIs. Other Power Purchase amounts will be determined in the final rate proposal.

### J. Transmission Purchases, Reserve/Ancillary Services

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 177,525 | 176,073 | * |

*The actual amount will be determined in the Final Rate Proposal

Generally, this category represents costs associated with services necessary to deliver energy from resources to markets and loads, such as transmission, ancillary services, and real power losses. Drivers of change are surplus levels and shape, change in Transmission's business practices, limited access to transmission – purchasing more expensive transmission products, and acquiring resources to meet Resource Adequacy.

**Summary of Comments Received:**
None

**Decision:** Transmission Purchases and Reserve and Ancillary Services will be determined in the Final Supplemental Rate Proposal.

**K. Residential Exchange Program**

| Original WP-07 | Initial IPR | Final IPR |
|---|---|---|
| 337,320 | 212,985 | *212,985 |

*The actual Residential Exchange benefits will be determined in the Final Rate Proposal.

For the current rate period (FY 2007-2009 from the WP-07 rate case) the program expense is a result of the Residential Exchange Program Settlement agreements with the Investor Owned Utilities (IOUs). A subsequent ruling from the 9th Circuit Court found these settlements beyond BPA's authority. As a result, BPA is holding a rate case to address the ruling, including re-setting rates for FY 2009. Residential Exchange Benefits for FY 2009 as reflected in BPA's WP-07 Initial Supplemental Rate Proposal are calculated as follows:

Eligible Residential Exchange Benefits = $259 million ($250 million for Investor Owned Utilities and $9 million for Consumer Owned Utilities)
Less any Deemer Balances = ($9 million )
Less Lookback Amounts for IOUs = ($39 million)
<u>Plus additional staffing to support program - $2 million (implementation costs of running the program)</u>
Net Residential Exchange Benefits in Initial Supplemental FY 2009 PF Rates = $213 million

**Decision:** Residential Exchange benefits will be determined in the Final Rate Proposal.

**L. Debt Management**

Debt management issues are not decided in the IPR. How BPA includes decisions and assumptions on debt management are rate case issues and will be discussed in that forum. However, BPA thought it important to show in the IPR the impact of past and future debt management decisions since these impact power rates. This IPR final report is intended to portray BPA's current thinking on these issues however does not make any decisions associated with debt management issues.

BPA's debt management process is largely driven by actual and forecasts of future capital investments in the FCRPS. Management of this program entails comprehensive review of options for reducing debt service costs based on assumptions about capital spending, interest rate yield curves, and retaining access to capital. However, the primary driver of costs in this area is capital spending levels. The IPR includes discussion on these items because it is important for participants to understand the implications of past debt management decisions and proposed capital spending levels. That said, review during the IPR has led to some changes, the impacts of which are estimated here. The levels for these cost categories may be different in the Final Rate Proposal.

**Total Net Interest, Amortization/Depreciation and Non-Federal Debt Service**

| Original WP-07 | Initial IPR | Final IPR* |
|---|---|---|
| 937,393 | 911,946 | 907,587 |

**Net Interest**

| Original WP-07 | Initial IPR | Final IPR* |
|---|---|---|
| 177,499 | 155,411 | 154,787 |

**Amortization/Depreciation**

| Original WP-07 | Initial IPR | Final IPR* |
|---|---|---|
| 205,857 | 191,509 | 188,580 |

**Non-Federal Debt Service**

| Original WP-07 | Initial IPR | Final IPR* |
|---|---|---|
| 554,014 | 564,466 | 564,220 |

* The actual amount will be determined in the Final Rate Proposal.

Changes since the initial IPR numbers reflect the decisions described above in Section B, Corps and Reclamation, related to the revised CRFM Plant-In-Service estimate and decreased Conservation capital for FY 2009. In addition, BPA modified an assumption in the repayment study, as described in the debt management workshop. CRFM studies that were placed into service in FY 2006 and 2007 had been included in the initial IPR repayment study with a 15-year life, but have been modified to reflect the 50-year repayment period and 75-year amortization period as they had in the original WP-07 rate proposal. Other changes that affect the current estimates are revised estimates of FY 2008 investments and revised reserves estimates resulting in different interest earnings assumptions. The final levels of these forecasts will be determined in the final rate proposal.

# APPENDIX B

# REPAYMENT PROGRAM TABLES

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## DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table 10 shows the amortization results from the Generation repayment studies for FY 2008-2009, summarized by bonds, appropriations, and irrigation due and discretionary, by year.

Tables 11-A through 12-G are reserved for FY 2007-2008. Since this Supplemental Proposal addressed only changes to FY 2009, these tables are not displayed in this Study.

Tables 13A through 13G show the results from the Generation repayment studies for FY -2009, respectively, using revenues from current rates. Table 14 provides the application of amortization through the repayment period for generation based upon the revenues forecast using current rates.

Table 13A displays the repayment program results for generation for FY 2009. The first column shows the applicable fiscal year. The second column shows the total investment costs of the generating projects through the cost evaluation period. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 4.) In the third column, forecasted replacements required to maintain the system are displayed through the repayment period. (*See* Documentation, WP-07-FS-BPA-10A, Chapter 10.) The fourth column shows the cumulative dollar amount of the generation investment placed in service. This is comprised of historical plant-in-service, planned replacements and additions to plant through the cost evaluation period, and replacements from the end of the cost evaluation period to the end of the repayment study period. For these studies, all additional plant is assumed to be financed by either appropriations or bonds.

The next two columns show scheduled amortization payments for each year of the repayment period. Discretionary amortization shows generation amortization payments made before the due dates of each particular obligation. Unamortized investments, shown in column 7, are determined by taking the previous year's unamortized amount, adding any replacements, subtracting amortization, and subtracting discretionary amortization. Columns 8, 9, and 10 show a similar calculation of predetermined amortization payments and the unamortized amount of irrigation assistance for each year of the repayment period. Irrigation assistance is assigned 100 percent to generation.

Table 13B displays planned principal payments by fiscal year for Federal generation obligations. Shown on these tables are the principal payments associated with the appropriations of the COE and Reclamation, and BPA bonds.

Table 13C shows the component of the capitalized contractual obligations associated with payment of principal. Included is the stream of payments associated with a long-term, relatively fixed, energy resource acquisition contract that will not be capitalized. The capitalized contractual obligations are 100 percent generation-related.

Table 13D shows the planned interest payments by fiscal year for Federal generation obligations. Shown on these tables are the interest payments associated with the appropriations of the COE and Reclamation, and BPA bonds.

Table 13E shows the component of the capitalized contractual obligations associated with payment of interest expense. Included is the stream of payments associated with a long-term, relatively fixed, energy resource acquisition contract that will not be capitalized. The capitalized contractual obligations are 100 percent generation-related.

Table 13F shows a summary of all Federal and capitalized contract generation principal and interest payments.

Table 13G compares the schedule of unamortized Federal generation obligations resulting from the Generation repayment studies to those obligations that are due and must be paid for each year of the repayment period. Column 2 shows unamortized obligations and is identical to the data shown in Column 7 of Table 13A. Column 3 shows obligations that are due for each year. It should be noted that unamortized obligations are always less than the term schedule, indicating that planned repayments are in excess of repayment obligations, thereby satisfying repayment requirements. The total of Unamortized Investment need not necessarily be zero at the end of the repayment period because of the replacements occurring subsequent to the cost evaluation period.

Table 14 lists by year through the 50-year repayment period the application of the generation amortization payments, consistent with the revised repayment studies, by project. The projected annual amortization payments on the generation obligations are identified by the project name, in-service date, due date, and interest rate. The amount of the obligation is shown as both the original gross amount due and the net amount after all prior amortization payments.

**Table 10**

AMORTIZATION - GENERATION
REPAYMENT STUDY FOR FINAL SUPPLEMENTAL PROPOSAL
FY2008 - 2009
($000s)

| Maturing/Due | | |
|---|---|---|
| Bonds | | |
| | 2008 | 157,481 |
| | 2009 | 92,990 |
| | | 250,471 |
| Appropriations | | |
| | 2008 | 0 |
| | 2009 | 0 |
| | | 0 |
| Irrigation Assistance | | |
| | 2008 | 2,950 |
| | 2009 | 6,590 |
| | | 9,540 |
| | **TOTAL** | **260,011** |

| Scheduled But Not Yet Due | | |
|---|---|---|
| Bonds | | |
| | 2008 | 0 |
| | 2009 | 0 |
| | | 0 |
| Appropriations | | |
| | 2008 | 120,300 |
| | 2009 | 10,075 |
| | | 130,375 |
| | **TOTAL** | **130,375** |

| Total by Year | | |
|---|---|---|
| Bonds | | |
| | 2008 | 157,481 |
| | 2009 | 92,990 |
| | | 250,471 |
| Appropriations | | |
| | 2008 | 120,300 |
| | 2009 | 10,075 |
| | | 130,375 |
| Irrigation Assistance | | |
| | 2008 | 2,950 |
| | 2009 | 7,279 |
| | | 10,229 |
| Total | | |
| | 2008 | 280,731 |
| | 2009 | 110,344 |
| | | **391,075** |

Table 13A: Generation Investments Placed in Service FY 2009 ($000s)

| | **Investment Placed in Service** | | | | | | | **Irrigation Assistance** | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Date** | **Initial Project** | **Replacements** | **Cumulative Amount in Service** | **Due Amortization** | **Discretionary Amortization** | **UnAmortized Investment** | **Term Investment Schedule** | **Cumulative Amount in Serivce** | **Amortization** | **Unamortized Amount** |
| **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | **(6)** | **(7)** | | **(8)** | **(9)** | **(10)** |
| 09/30/2007 | 4,120,277 | 42,792 | 4,163,068 | 0 | 0 | 4,163,068 | 5,460,520 | 689,223 | 0 | 689,223 |
| 09/30/2008 | 399,000 | 0 | 4,562,068 | 157,481 | 120,300 | 4,284,287 | 5,377,944 | | 2,950 | 686,273 |
| 09/30/2009 | 333,152 | 0 | 4,895,220 | 92,990 | 10,075 | 4,514,374 | 5,278,921 | | 7,279 | 678,994 |
| 09/30/2010 | 0 | 126,180 | 5,021,400 | 144,749 | 50,410 | 4,445,395 | 5,152,890 | | 0 | 678,994 |
| 09/30/2011 | 0 | 117,932 | 5,139,332 | 135,000 | 11,592 | 4,416,735 | 5,123,251 | | 34,863 | 644,131 |
| 09/30/2012 | 0 | 110,125 | 5,249,457 | 75,000 | 0 | 4,451,860 | 5,107,853 | | 14,966 | 629,164 |
| 09/30/2013 | 0 | 102,832 | 5,352,289 | 132,800 | 0 | 4,421,892 | 4,935,745 | | 11,141 | 618,023 |
| 09/30/2014 | 0 | 103,207 | 5,455,496 | 65,850 | 32,319 | 4,426,930 | 4,973,280 | | 53,271 | 564,752 |
| 09/30/2015 | 0 | 103,601 | 5,559,097 | 0 | 57,204 | 4,473,327 | 4,954,725 | | 125,274 | 439,478 |
| 09/30/2016 | 0 | 103,993 | 5,663,090 | 0 | 0 | 4,577,320 | 5,053,849 | | 41,453 | 398,025 |
| 09/30/2017 | 0 | 104,447 | 5,767,537 | 0 | 0 | 4,681,767 | 5,089,996 | | 2 | 398,023 |
| 09/30/2018 | 0 | 104,961 | 5,872,498 | 0 | 136,876 | 4,649,851 | 5,147,567 | | 27,931 | 370,092 |
| 09/30/2019 | 0 | 105,532 | 5,978,030 | 20,000 | 596,667 | 4,138,716 | 5,126,130 | | 57,985 | 312,107 |
| 09/30/2020 | 0 | 106,154 | 6,084,184 | 0 | 603,966 | 3,640,904 | 5,121,245 | | 24,955 | 287,152 |
| 09/30/2021 | 0 | 106,827 | 6,191,011 | 0 | 652,692 | 3,095,039 | 5,142,000 | | 12,463 | 274,689 |
| 09/30/2022 | 0 | 107,545 | 6,298,556 | 0 | 690,189 | 2,512,396 | 5,179,578 | | 14,655 | 260,034 |
| 09/30/2023 | 0 | 95,731 | 6,394,287 | 25,000 | 706,531 | 1,876,596 | 5,075,303 | | 11,371 | 248,663 |
| 09/30/2024 | 0 | 85,358 | 6,479,645 | 50,000 | 657,852 | 1,254,102 | 5,151,616 | | 17,209 | 231,454 |
| 09/30/2025 | 0 | 76,207 | 6,555,852 | 0 | 620,584 | 709,725 | 4,986,747 | | 13,896 | 217,558 |
| 09/30/2026 | 0 | 68,142 | 6,623,994 | 0 | 642,916 | 134,951 | 4,817,284 | | 21,250 | 196,308 |
| 09/30/2027 | 0 | 61,037 | 6,685,031 | 0 | 80,988 | 115,000 | 4,765,939 | | 196,308 | 0 |
| 09/30/2028 | 0 | 54,710 | 6,739,741 | 0 | 54,710 | 115,000 | 4,603,310 | | 0 | 0 |
| 09/30/2029 | 0 | 49,119 | 6,788,860 | 0 | 49,119 | 115,000 | 4,393,986 | | 0 | 0 |
| 09/30/2030 | 0 | 44,228 | 6,833,088 | 0 | 44,228 | 115,000 | 4,434,179 | | 0 | 0 |
| 09/30/2031 | 0 | 39,875 | 6,872,963 | 30,000 | 39,875 | 85,000 | 4,430,872 | | 0 | 0 |
| 09/30/2032 | 0 | 36,033 | 6,908,996 | 0 | 36,033 | 85,000 | 4,259,642 | | 0 | 0 |
| 09/30/2033 | 0 | 51,481 | 6,960,477 | 0 | 51,481 | 85,000 | 4,010,722 | | 0 | 0 |
| 09/30/2034 | 0 | 51,949 | 7,012,426 | 0 | 51,949 | 85,000 | 4,061,590 | | 0 | 0 |
| 09/30/2035 | 0 | 52,461 | 7,064,887 | 0 | 52,461 | 85,000 | 4,064,745 | | 0 | 0 |
| 09/30/2036 | 0 | 52,957 | 7,117,844 | 0 | 52,957 | 85,000 | 4,116,336 | | 0 | 0 |
| 09/30/2037 | 0 | 53,494 | 7,171,338 | 0 | 53,494 | 85,000 | 4,096,181 | | 0 | 0 |
| 09/30/2038 | 0 | 54,070 | 7,225,408 | 0 | 54,070 | 85,000 | 4,130,277 | | 0 | 0 |
| 09/30/2039 | 0 | 54,684 | 7,280,092 | 45,000 | 54,684 | 40,000 | 4,183,823 | | 0 | 0 |
| 09/30/2040 | 0 | 55,280 | 7,335,372 | 0 | 55,280 | 40,000 | 4,235,195 | | 0 | 0 |
| 09/30/2041 | 0 | 55,911 | 7,391,283 | 0 | 55,911 | 40,000 | 4,281,191 | | 0 | 0 |
| 09/30/2042 | 0 | 56,577 | 7,447,860 | 0 | 56,577 | 40,000 | 4,335,716 | | 0 | 0 |
| 09/30/2043 | 0 | 53,302 | 7,501,162 | 15,000 | 53,302 | 25,000 | 4,220,430 | | 0 | 0 |
| 09/30/2044 | 0 | 50,220 | 7,551,382 | 0 | 50,220 | 25,000 | 4,202,818 | | 0 | 0 |
| 09/30/2045 | 0 | 47,374 | 7,598,756 | 0 | 47,374 | 25,000 | 4,160,260 | | 0 | 0 |

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Table 13A: Generation Investments Placed in Service FY 2009 ($000s)

| | Investment Placed in Service | | | | | | | Irrigation Assistance | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Date** | **Initial Project** | **Replacements** | **Cumulative Amount in Service** | **Due Amortization** | **Discretionary Amortization** | **UnAmortized Investment** | **Term Investment Schedule** | **Cumulative Amount in Serivce** | **Amortization** | **Unamortized Amount** |
| 09/30/2046 | 0 | 44,703 | 7,643,459 | 0 | 44,703 | 25,000 | 4,175,191 | | 0 | 0 |
| 09/30/2047 | 0 | 42,201 | 7,685,660 | 25,000 | 42,201 | 0 | 4,147,093 | | 0 | 0 |
| 09/30/2048 | 0 | 39,862 | 7,725,522 | 0 | 39,862 | 0 | 4,141,125 | | 0 | 0 |
| 09/30/2049 | 0 | 35,966 | 7,761,488 | 0 | 35,966 | 0 | 4,132,342 | | 0 | 0 |
| 09/30/2050 | 0 | 32,499 | 7,793,987 | 0 | 32,499 | 0 | 4,077,558 | | 0 | 0 |
| 09/30/2051 | 0 | 29,444 | 7,823,431 | (0) | 29,444 | 0 | 3,997,454 | | 0 | 0 |
| 09/30/2052 | 0 | 26,740 | 7,850,171 | (0) | 26,740 | 0 | 4,009,710 | | 0 | 0 |
| 09/30/2053 | 0 | 41,875 | 7,892,046 | (0) | 41,875 | 0 | 3,975,127 | | 0 | 0 |
| 09/30/2054 | 0 | 42,436 | 7,934,482 | 0 | 42,436 | 0 | 3,765,324 | | 0 | 0 |
| 09/30/2055 | 0 | 43,028 | 7,977,510 | (0) | 43,028 | 0 | 3,511,309 | | 0 | 0 |
| 09/30/2056 | 0 | 43,649 | 8,021,159 | (0) | 43,649 | 0 | 3,058,468 | | 0 | 0 |
| 09/30/2057 | 0 | 44,255 | 8,065,414 | 0 | 44,255 | 0 | 2,941,340 | | 0 | 0 |
| 09/30/2058 | 0 | 44,890 | 8,110,304 | 0 | 44,890 | 0 | 2,700,603 | | 0 | 0 |
| 09/30/2059 | 0 | 45,553 | 8,155,857 | 0 | 45,553 | 0 | 2,599,544 | | 0 | 0 |
| 09/30/2060 | 0 | 0 | 8,155,857 | 0 | 0 | 0 | 2,498,099 | | 0 | 0 |
| 09/30/2061 | 0 | 0 | 8,155,857 | 0 | 0 | 0 | 2,396,271 | | 0 | 0 |
| 09/30/2062 | 0 | 0 | 8,155,857 | 0 | 0 | 0 | 2,293,998 | | 0 | 0 |
| 09/30/2063 | 0 | 0 | 8,155,857 | 0 | 0 | 0 | 2,191,222 | | 0 | 0 |
| | **$4,852,429** | **$3,303,429** | | **$1,013,870** | **$7,141,987** | | | | **$689,223** | |

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Table 13B: Federal Principal Payments FY 2009 ($000s)

| Date | BPA Bonds | Corps of Engineers Appropriations | Bureau of Reclamation Appropriations | Irrigation Amortization |
|---|---|---|---|---|
| 09/30/2008 | 157,481 | 120,300 | - | 2,950 |
| 09/30/2009 | 92,990 | 10,075 | - | 7,279 |
| 09/30/2010 | 144,749 | 50,410 | - | - |
| 09/30/2011 | 135,000 | 11,592 | - | 34,863 |
| 09/30/2012 | 65,000 | - | - | 14,966 |
| 09/30/2013 | 132,800 | - | - | 11,141 |
| 09/30/2014 | 65,850 | 31,452 | 867 | 53,271 |
| 09/30/2015 | - | 57,204 | - | 125,274 |
| 09/30/2016 | - | - | - | 41,453 |
| 09/30/2017 | - | - | - | 2 |
| 09/30/2018 | - | 136,876 | - | 27,931 |
| 09/30/2019 | 20,000 | 452,375 | 144,292 | 57,985 |
| 09/30/2020 | - | 451,796 | 152,170 | 24,955 |
| 09/30/2021 | - | 472,006 | 180,686 | 12,463 |
| 09/30/2022 | - | 642,154 | 48,035 | 14,655 |
| 09/30/2023 | 25,000 | 706,531 | - | 11,371 |
| 09/30/2024 | 178,238 | 375,914 | 80,986 | 17,209 |
| 09/30/2025 | - | 619,751 | 833 | 13,896 |
| 09/30/2026 | - | 627,695 | 15,221 | 21,250 |
| 09/30/2027 | - | 80,988 | - | 196,308 |
| 09/30/2028 | - | 54,710 | - | - |
| 09/30/2029 | - | 49,119 | - | - |
| 09/30/2030 | - | 44,228 | - | - |
| 09/30/2031 | 30,000 | 39,875 | - | - |
| 09/30/2032 | - | 36,033 | - | - |
| 09/30/2033 | - | 51,481 | - | - |
| 09/30/2034 | - | 51,949 | - | - |
| 09/30/2035 | - | 52,461 | - | - |
| 09/30/2036 | - | 52,957 | - | - |
| 09/30/2037 | - | 53,494 | - | - |
| 09/30/2038 | - | 54,070 | - | - |
| 09/30/2039 | 45,000 | 54,684 | - | - |
| 09/30/2040 | - | 55,280 | - | - |
| 09/30/2041 | - | 55,911 | - | - |
| 09/30/2042 | - | 56,577 | - | - |
| 09/30/2043 | 15,000 | 53,302 | - | - |
| 09/30/2044 | - | 50,220 | - | - |
| 09/30/2045 | - | 47,374 | 0 | - |
| 09/30/2046 | - | 44,703 | 0 | - |
| 09/30/2047 | 25,000 | 42,201 | 0 | - |
| 09/30/2048 | - | 39,862 | - | - |
| 09/30/2049 | - | 35,966 | - | - |
| 09/30/2050 | - | 32,499 | - | - |
| 09/30/2051 | - | 29,444 | (0) | - |
| 09/30/2052 | - | 26,740 | - | - |

Table 13B: Federal Principal Payments FY 2009 ($000s)

| Date | BPA Bonds | Corps of Engineers Appropriations | Bureau of Reclamation Appropriations | Irrigation Amortization |
|---|---|---|---|---|
| 09/30/2053 | - | 41,875 | - | - |
| 09/30/2054 | - | 42,436 | - | - |
| 09/30/2055 | - | 43,028 | (0) | - |
| 09/30/2056 | - | 43,649 | - | - |
| 09/30/2057 | - | 44,255 | 0 | - |
| 09/30/2058 | - | 44,890 | - | - |
| 09/30/2059 | - | - | - | - |
| | - | (0) | - | - |
| **Total** | **1,132,108** | **6,272,392** | **623,090** | **689,223** |

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Table 13C: Component of Capitalized Contract Principal Payments FY 2009 ($000s)

| Fiscal Year | Supply System Projects | Trojan | Other | Total |
|---|---|---|---|---|
| 2008 | 157,450 | 7,512 | 9,696 | 174,658 |
| 2009 | 265,499 | 0 | 10,161 | 275,660 |
| 2010 | 275,047 | 0 | 10,647 | 285,694 |
| 2011 | 310,343 | 0 | 11,148 | 321,492 |
| 2012 | 411,702 | 0 | 11,699 | 423,401 |
| 2013 | 370,869 | 0 | 12,277 | 383,146 |
| 2014 | 389,465 | 0 | 12,895 | 402,360 |
| 2015 | 399,071 | 0 | 8,818 | 407,888 |
| 2016 | 553,635 | 0 | 8,943 | 562,579 |
| 2017 | 618,597 | 0 | 9,403 | 628,000 |
| 2018 | 488,765 | 0 | 9,873 | 498,638 |
| 2019 | 26,889 | 0 | 10,367 | 37,255 |
| 2020 | 108,940 | 0 | 10,886 | 119,826 |
| 2021 | 114,526 | 0 | 11,435 | 125,961 |
| 2022 | 120,319 | 0 | 12,014 | 132,333 |
| 2023 | 126,405 | 0 | 13,028 | 139,433 |
| 2024 | 106,611 | 0 | 13,683 | 120,294 |
| 2025 | 33,483 | 0 | 353 | 33,835 |
| 2026 | 35,777 | 0 | 0 | 35,777 |
| 2027 | 38,228 | 0 | 0 | 38,228 |
| 2028 | 40,846 | 0 | 0 | 40,846 |
| 2029 | 43,644 | 0 | 0 | 43,644 |
| 2030 | 46,634 | 0 | 0 | 46,634 |
| 2031 | 49,828 | 0 | 0 | 49,828 |
| 2032 | 53,242 | 0 | 0 | 53,242 |
| 2033 | 56,889 | 0 | 0 | 56,889 |
| 2034 | 60,785 | 0 | 0 | 60,785 |
| 2035 | 64,949 | 0 | 0 | 64,949 |
| 2036 | 69,398 | 0 | 0 | 69,398 |
| 2037 | 74,152 | 0 | 0 | 74,152 |
| 2038 | 79,231 | 0 | 0 | 79,231 |
| 2039 | 84,659 | 0 | 0 | 84,659 |
| 2040 | 90,458 | 0 | 0 | 90,458 |
| 2041 | 96,654 | 0 | 0 | 96,654 |
| 2042 | 103,275 | 0 | 0 | 103,275 |
| 2043 | 110,349 | 0 | 0 | 110,349 |
| 2044 | 117,908 | 0 | 0 | 117,908 |
| 2045 | 125,984 | 0 | 0 | 125,984 |
| 2046 | 134,615 | 0 | 0 | 134,615 |
| 2047 | 143,836 | 0 | 0 | 143,836 |
| 2048 | 153,689 | 0 | 0 | 153,689 |
| 2049 | 164,216 | 0 | 0 | 164,216 |
| 2050 | 175,465 | 0 | 0 | 175,465 |
| 2051 | 187,485 | 0 | 0 | 187,485 |
| 2052 | 200,327 | 0 | 0 | 200,327 |

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Table 13C: Component of Capitalized Contract Principal Payments FY 2009 ($000s)

| Fiscal Year | Supply System Projects | Trojan | Other | Total |
|---|---|---|---|---|
| 2053 | 214,049 | 0 | 0 | 214,049 |
| 2054 | 228,712 | 0 | 0 | 228,712 |
| 2055 | 244,379 | 0 | 0 | 244,379 |
| 2056 | 261,118 | 0 | 0 | 261,118 |
| 2057 | 279,005 | 0 | 0 | 279,005 |
| 2058 | 298,117 | 0 | 0 | 298,117 |
| 2059 | 318,538 | 0 | 0 | 318,538 |
| 2060 | 250,970 | 0 | 0 | 250,970 |

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Table 13D: Federal Interest Payments FY 2009 ($000s)

| Date | BPA Bonds (1) | Corps of Engineers Appropriations (2) | Bureau of Reclamation Appropriations |
|---|---|---|---|
| 09/30/2008 | 30,052 | 177,545 | 43,198 |
| 09/30/2009 | 40,244 | 178,794 | 43,198 |
| 09/30/2010 | 37,730 | 184,369 | 43,198 |
| 09/30/2011 | 31,013 | 188,977 | 43,198 |
| 09/30/2012 | 27,783 | 195,855 | 43,198 |
| 09/30/2013 | 23,563 | 203,057 | 43,198 |
| 09/30/2014 | 15,544 | 209,782 | 43,198 |
| 09/30/2015 | 11,045 | 214,264 | 43,135 |
| 09/30/2016 | 14,242 | 216,927 | 43,135 |
| 09/30/2017 | 15,042 | 223,728 | 43,135 |
| 09/30/2018 | 11,077 | 230,558 | 43,135 |
| 09/30/2019 | (634) | 227,591 | 43,135 |
| 09/30/2020 | 210 | 202,134 | 32,814 |
| 09/30/2021 | 210 | 176,773 | 21,934 |
| 09/30/2022 | 210 | 150,011 | 9,015 |
| 09/30/2023 | 219 | 114,971 | 5,580 |
| 09/30/2024 | 7,472 | 75,025 | 5,580 |
| 09/30/2025 | (8,672) | 56,673 | 822 |
| 09/30/2026 | (8,677) | 27,259 | 780 |
| 09/30/2027 | (8,673) | 898 | - |
| 09/30/2028 | (8,669) | - | - |
| 09/30/2029 | (8,665) | - | - |
| 09/30/2030 | (8,660) | - | - |
| 09/30/2031 | (8,656) | - | - |
| 09/30/2032 | (10,645) | - | - |
| 09/30/2033 | (10,639) | - | - |
| 09/30/2034 | (10,633) | - | - |
| 09/30/2035 | (10,627) | - | - |
| 09/30/2036 | (10,620) | - | - |
| 09/30/2037 | (10,613) | - | - |
| 09/30/2038 | (10,605) | - | - |
| 09/30/2039 | (10,597) | - | - |
| 09/30/2040 | (13,570) | - | - |
| 09/30/2041 | (13,561) | - | - |
| 09/30/2042 | (13,551) | - | - |
| 09/30/2043 | (13,540) | - | - |
| 09/30/2044 | (14,523) | - | - |
| 09/30/2045 | (14,511) | - | - |
| 09/30/2046 | (14,498) | - | - |
| 09/30/2047 | (14,484) | - | - |
| 09/30/2048 | (15,986) | - | - |
| 09/30/2049 | (15,970) | - | - |
| 09/30/2050 | (15,953) | - | - |
| 09/30/2051 | (15,935) | - | - |
| 09/30/2052 | (15,915) | - | - |
| 09/30/2053 | (15,895) | - | - |
| 09/30/2054 | (15,872) | - | - |
| 09/30/2055 | (15,849) | - | - |
| 09/30/2056 | (15,823) | - | - |
| 09/30/2057 | (15,796) | - | - |
| 09/30/2058 | (15,767) | - | - |
| 09/30/2059 | (15,736) | - | - |
| | **-$183,364** | **$3,255,191** | **$594,587** |

(1) Net of interest income and AFUDC.

(2) Includes payments for Lower Snake Fish and Wildlife.

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Table 13E: Component of Capitalized Contract Interest Payments FY 2009 ($000s)

| Fiscal Year | Supply System Projects | Trojan | Other | Total |
|---|---|---|---|---|
| 2008 | 251,507 | 376 | 8,748 | 260,631 |
| 2009 | 279,794 | 0 | 8,765 | 288,559 |
| 2010 | 260,907 | 0 | 8,198 | 269,105 |
| 2011 | 241,579 | 0 | 7,534 | 249,113 |
| 2012 | 228,249 | 0 | 6,977 | 235,225 |
| 2013 | 212,496 | 0 | 6,378 | 218,874 |
| 2014 | 187,416 | 0 | 5,750 | 193,166 |
| 2015 | 151,569 | 0 | 5,209 | 156,778 |
| 2016 | 132,488 | 0 | 4,763 | 137,250 |
| 2017 | 101,362 | 0 | 4,301 | 105,663 |
| 2018 | 63,058 | 0 | 3,816 | 66,874 |
| 2019 | 30,266 | 0 | 3,307 | 33,573 |
| 2020 | 28,884 | 0 | 2,772 | 31,656 |
| 2021 | 23,303 | 0 | 2,211 | 25,514 |
| 2022 | 17,499 | 0 | 1,621 | 19,120 |
| 2023 | 11,410 | 0 | 991 | 12,401 |
| 2024 | 80,923 | 0 | 341 | 81,264 |
| 2025 | 303,250 | 0 | 9 | 303,259 |
| 2026 | 301,104 | 0 | 0 | 301,104 |
| 2027 | 298,810 | 0 | 0 | 298,810 |
| 2028 | 296,360 | 0 | 0 | 296,360 |
| 2029 | 293,742 | 0 | 0 | 293,742 |
| 2030 | 290,944 | 0 | 0 | 290,944 |
| 2031 | 287,955 | 0 | 0 | 287,955 |
| 2032 | 284,761 | 0 | 0 | 284,761 |
| 2033 | 281,348 | 0 | 0 | 281,348 |
| 2034 | 277,702 | 0 | 0 | 277,702 |
| 2035 | 273,805 | 0 | 0 | 273,805 |
| 2036 | 269,642 | 0 | 0 | 269,642 |
| 2037 | 265,194 | 0 | 0 | 265,194 |
| 2038 | 260,441 | 0 | 0 | 260,441 |
| 2039 | 255,362 | 0 | 0 | 255,362 |
| 2040 | 249,935 | 0 | 0 | 249,935 |
| 2041 | 244,137 | 0 | 0 | 244,137 |
| 2042 | 237,941 | 0 | 0 | 237,941 |
| 2043 | 231,321 | 0 | 0 | 231,321 |
| 2044 | 224,248 | 0 | 0 | 224,248 |
| 2045 | 216,690 | 0 | 0 | 216,690 |
| 2046 | 208,615 | 0 | 0 | 208,615 |
| 2047 | 199,986 | 0 | 0 | 199,986 |
| 2048 | 190,766 | 0 | 0 | 190,766 |
| 2049 | 180,915 | 0 | 0 | 180,915 |
| 2050 | 170,388 | 0 | 0 | 170,388 |
| 2051 | 159,141 | 0 | 0 | 159,141 |
| 2052 | 147,123 | 0 | 0 | 147,123 |
| 2053 | 134,282 | 0 | 0 | 134,282 |
| 2054 | 120,562 | 0 | 0 | 120,562 |
| 2055 | 105,901 | 0 | 0 | 105,901 |
| 2056 | 90,237 | 0 | 0 | 90,237 |
| 2057 | 73,499 | 0 | 0 | 73,499 |

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Table 13F: Summary of Payments
FY 2009 ($000s)

| | Principal | | | Interest | | |
|---|---|---|---|---|---|---|
| Date | Generation Payment | Capitalized Contracts Payment | Total Principal Payment | Generation Payment | Capitalized Contracts Payment | Total Interest Payment |
| 09/30/2008 | 280,731 | 174,658 | 455,389 | 250,794 | 260,631 | 260,631 |
| 09/30/2009 | 110,344 | 275,660 | 386,004 | 262,236 | 288,559 | 550,796 |
| 09/30/2010 | 195,159 | 285,694 | 480,853 | 265,296 | 269,105 | 534,401 |
| 09/30/2011 | 181,455 | 321,492 | 502,947 | 263,188 | 249,113 | 512,301 |
| 09/30/2012 | 79,966 | 423,401 | 503,368 | 266,836 | 235,225 | 502,061 |
| 09/30/2013 | 143,941 | 383,146 | 527,087 | 269,818 | 218,874 | 488,692 |
| 09/30/2014 | 151,440 | 402,360 | 553,800 | 268,524 | 193,166 | 461,690 |
| 09/30/2015 | 182,479 | 407,888 | 590,367 | 268,444 | 156,778 | 425,222 |
| 09/30/2016 | 41,453 | 562,579 | 604,031 | 274,304 | 137,250 | 411,554 |
| 09/30/2017 | 2 | 628,000 | 628,002 | 281,905 | 105,663 | 387,569 |
| 09/30/2018 | 164,807 | 498,638 | 663,445 | 284,771 | 66,874 | 351,645 |
| 09/30/2019 | 674,652 | 37,255 | 711,908 | 270,093 | 33,573 | 303,666 |
| 09/30/2020 | 628,921 | 119,826 | 748,747 | 235,158 | 31,656 | 266,814 |
| 09/30/2021 | 665,155 | 125,961 | 791,116 | 198,917 | 25,514 | 224,430 |
| 09/30/2022 | 704,844 | 132,333 | 837,177 | 159,236 | 19,120 | 178,355 |
| 09/30/2023 | 742,902 | 139,433 | 882,335 | 120,770 | 12,401 | 133,171 |
| 09/30/2024 | 652,347 | 120,294 | 772,641 | 88,077 | 81,264 | 169,341 |
| 09/30/2025 | 634,480 | 33,835 | 668,315 | 48,824 | 303,259 | 352,083 |
| 09/30/2026 | 664,166 | 35,777 | 699,942 | 19,361 | 301,104 | 320,465 |
| 09/30/2027 | 277,296 | 38,228 | 315,524 | -7,775 | 298,810 | 291,035 |
| 09/30/2028 | 54,710 | 40,846 | 95,556 | -8,669 | 296,360 | 287,691 |
| 09/30/2029 | 49,119 | 43,644 | 92,763 | -8,665 | 293,742 | 285,077 |
| 09/30/2030 | 44,228 | 46,634 | 90,862 | -8,660 | 290,944 | 282,284 |
| 09/30/2031 | 69,875 | 49,828 | 119,703 | -8,656 | 287,955 | 279,299 |
| 09/30/2032 | 36,033 | 53,242 | 89,275 | -10,645 | 284,761 | 274,116 |
| 09/30/2033 | 51,481 | 56,889 | 108,370 | -10,639 | 281,348 | 270,709 |
| 09/30/2034 | 51,949 | 60,785 | 112,734 | -10,633 | 277,702 | 267,068 |
| 09/30/2035 | 52,461 | 64,949 | 117,410 | -10,627 | 273,805 | 263,178 |
| 09/30/2036 | 52,957 | 69,398 | 122,355 | -10,620 | 269,642 | 259,022 |
| 09/30/2037 | 53,494 | 74,152 | 127,646 | -10,613 | 265,194 | 254,581 |
| 09/30/2038 | 54,070 | 79,231 | 133,301 | -10,605 | 260,441 | 249,835 |
| 09/30/2039 | 99,684 | 84,659 | 184,343 | -10,597 | 255,362 | 244,765 |
| 09/30/2040 | 55,280 | 90,458 | 145,738 | -13,570 | 249,935 | 236,365 |
| 09/30/2041 | 55,911 | 96,654 | 152,565 | -13,561 | 244,137 | 230,576 |
| 09/30/2042 | 56,577 | 103,275 | 159,852 | -13,551 | 237,941 | 224,390 |
| 09/30/2043 | 68,302 | 110,349 | 178,651 | -13,540 | 231,321 | 217,781 |

BONNEVILLE POWER ADMINISTRATION
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Table 13F: Summary of Payments
FY 2009 ($000s)

| | Principal | | | Interest | | |
|---|---|---|---|---|---|---|
| **Date** | **Generation Payment** | **Capitalized Contracts Payment** | **Total Principal Payment** | **Generation Payment** | **Capitalized Contracts Payment** | **Total Interest Payment** |
| 09/30/2044 | 50,220 | 117,908 | 168,128 | -14,523 | 224,248 | 209,725 |
| 09/30/2045 | 47,374 | 125,984 | 173,358 | -14,511 | 216,690 | 202,180 |
| 09/30/2046 | 44,703 | 134,615 | 179,318 | -14,498 | 208,615 | 194,117 |
| 09/30/2047 | 67,201 | 143,836 | 211,037 | -14,484 | 199,986 | 185,502 |
| 09/30/2048 | 39,862 | 153,689 | 193,551 | -15,986 | 190,766 | 174,780 |
| 09/30/2049 | 35,966 | 164,216 | 200,182 | -15,970 | 180,915 | 164,944 |
| 09/30/2050 | 32,499 | 175,465 | 207,964 | -15,953 | 170,388 | 154,435 |
| 09/30/2051 | 29,444 | 187,485 | 216,928 | -15,935 | 159,141 | 143,206 |
| 09/30/2052 | 26,740 | 200,327 | 227,067 | -15,915 | 147,123 | 131,208 |
| 09/30/2053 | 41,875 | 214,049 | 255,924 | -15,895 | 134,282 | 118,388 |
| 09/30/2054 | 42,436 | 228,712 | 271,148 | -15,872 | 120,562 | 104,689 |
| 09/30/2055 | 43,028 | 244,379 | 287,406 | -15,849 | 105,901 | 90,053 |
| 09/30/2056 | 43,649 | 261,118 | 304,767 | -15,823 | 90,237 | 74,414 |
| 09/30/2057 | 44,255 | 279,005 | 323,260 | -15,796 | 73,499 | 57,703 |
| 09/30/2058 | 44,890 | 298,117 | 343,007 | -15,767 | 55,615 | 39,848 |
| 09/30/2059 | 0 | 318,538 | 318,538 | -15,736 | 36,505 | 20,770 |
| | **$8,716,813** | **$9,518,887** | **$18,235,701** | **$3,666,413** | **$9,903,002** | **$13,318,621** |

BONNEVILLE POWER ADMINISTRATION
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Table 13G: Summary of Federal Outstanding Balance FY 2009 ($000s)

| Date | Unamortized Investment | Term Schedule |
|---|---|---|
| 09/30/2007 | 4,163,068 | 5,460,520 |
| 09/30/2008 | 4,284,287 | 5,377,944 |
| 09/30/2009 | 4,514,374 | 5,278,921 |
| 09/30/2010 | 4,445,395 | 5,152,890 |
| 09/30/2011 | 4,416,735 | 5,123,251 |
| 09/30/2012 | 4,451,860 | 5,107,853 |
| 09/30/2013 | 4,421,892 | 4,935,745 |
| 09/30/2014 | 4,426,930 | 4,973,280 |
| 09/30/2015 | 4,473,327 | 4,954,725 |
| 09/30/2016 | 4,577,320 | 5,053,849 |
| 09/30/2017 | 4,681,767 | 5,089,996 |
| 09/30/2018 | 4,649,851 | 5,147,567 |
| 09/30/2019 | 4,138,716 | 5,126,130 |
| 09/30/2020 | 3,640,904 | 5,121,245 |
| 09/30/2021 | 3,095,039 | 5,142,000 |
| 09/30/2022 | 2,512,396 | 5,179,578 |
| 09/30/2023 | 1,876,596 | 5,075,303 |
| 09/30/2024 | 1,254,102 | 5,151,616 |
| 09/30/2025 | 709,725 | 4,986,747 |
| 09/30/2026 | 134,951 | 4,817,284 |
| 09/30/2027 | 115,000 | 4,765,939 |
| 09/30/2028 | 115,000 | 4,603,310 |
| 09/30/2029 | 115,000 | 4,393,986 |
| 09/30/2030 | 115,000 | 4,434,179 |
| 09/30/2031 | 85,000 | 4,430,872 |
| 09/30/2032 | 85,000 | 4,259,642 |
| 09/30/2033 | 85,000 | 4,010,722 |
| 09/30/2034 | 85,000 | 4,061,590 |
| 09/30/2035 | 85,000 | 4,064,745 |
| 09/30/2036 | 85,000 | 4,116,336 |
| 09/30/2037 | 85,000 | 4,096,181 |
| 09/30/2038 | 85,000 | 4,130,277 |
| 09/30/2039 | 40,000 | 4,183,823 |
| 09/30/2040 | 40,000 | 4,235,195 |
| 09/30/2041 | 40,000 | 4,281,191 |
| 09/30/2042 | 40,000 | 4,335,716 |
| 09/30/2043 | 25,000 | 4,220,430 |
| 09/30/2044 | 25,000 | 4,202,818 |
| 09/30/2045 | 25,000 | 4,160,260 |
| 09/30/2046 | 25,000 | 4,175,191 |
| 09/30/2047 | 0 | 4,147,093 |
| 09/30/2048 | 0 | 4,141,125 |
| 09/30/2049 | 0 | 4,132,342 |
| 09/30/2050 | 0 | 4,077,558 |
| 09/30/2051 | 0 | 3,997,454 |
| 09/30/2052 | 0 | 4,009,710 |
| 09/30/2053 | 0 | 3,975,127 |
| 09/30/2054 | 0 | 3,765,324 |
| 09/30/2055 | 0 | 3,511,309 |
| 09/30/2056 | 0 | 3,058,468 |
| 09/30/2057 | 0 | 2,941,340 |
| 09/30/2058 | 0 | 2,700,603 |

Table 14:  Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2008 | BPA PROGRAM | 1998 | 2008 | 3,181 | 3,181 | 5.75% | No | No | 3,181 |
| FY 2008 | CONSERVATION | 1998 | 2008 | 104,300 | 104,300 | 5.30% | No | No | 104,300 |
| FY 2008 | BUREAU DIRECT FUND | 2005 | 2008 | 20,000 | 20,000 | 3.50% | No | No | 20,000 |
| FY 2008 | CONSERVATION | 2004 | 2008 | 30,000 | 30,000 | 2.95% | No | No | 30,000 |
| FY 2008 | JOHN DAY | 1969 | 2019 | 96,104 | 13,707 | 7.27% | No | No | 13,707 |
| FY 2008 | BONNEVILLE | 1995 | 2020 | 20 | 20 | 7.25% | No | No | 20 |
| FY 2008 | BONNEVILLE | 1995 | 2020 | 22 | 22 | 7.25% | Yes | No | 22 |
| FY 2008 | GREEN PETER-FOSTER | 1995 | 2020 | 11 | 11 | 7.25% | No | No | 11 |
| FY 2008 | GREEN PETER-FOSTER | 1995 | 2020 | 24 | 24 | 7.25% | No | No | 24 |
| FY 2008 | JOHN DAY | 1970 | 2020 | 23,656 | 23,656 | 7.25% | No | No | 23,656 |
| FY 2008 | JOHN DAY | 1995 | 2020 | 79 | 79 | 7.25% | No | No | 79 |
| FY 2008 | LITTLE GOOSE | 1970 | 2020 | 22,326 | 21,301 | 7.25% | No | No | 21,301 |
| FY 2008 | LOWER MONUMENTAL | 1970 | 2020 | 51,218 | 51,218 | 7.25% | No | No | 51,218 |
| FY 2008 | LOWER MONUMENTAL | 1971 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1972 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1973 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1974 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1975 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1976 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1977 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1978 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1979 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1980 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1981 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1982 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1983 | 2020 | 214 | 214 | 7.25% | Yes | No | 214 |
| FY 2008 | LOWER MONUMENTAL | 1985 | 2020 | 8 | 8 | 7.25% | No | No | 8 |
| FY 2008 | LOWER MONUMENTAL | 1986 | 2020 | 132 | 132 | 7.25% | No | No | 132 |
| FY 2008 | LOWER MONUMENTAL | 1987 | 2020 | 3 | 3 | 7.25% | No | No | 3 |
| FY 2008 | DWORSHAK | 1996 | 2021 | 26 | 26 | 7.23% | No | No | 26 |
| FY 2008 | DWORSHAK | 1996 | 2021 | 184 | 184 | 7.23% | No | No | 184 |
| FY 2008 | LITTLE GOOSE | 1971 | 2021 | 42,962 | 42,962 | 7.23% | No | No | 6,278 |
| FY 2008 | LITTLE GOOSE | 1972 | 2021 | 28 | 28 | 7.23% | Yes | No | 28 |
| FY 2008 | LITTLE GOOSE | 1973 | 2021 | 29 | 29 | 7.23% | Yes | No | 29 |
| FY 2008 | LITTLE GOOSE | 1974 | 2021 | 28 | 28 | 7.23% | Yes | No | 28 |
| FY 2008 | LITTLE GOOSE | 1975 | 2021 | 29 | 29 | 7.23% | Yes | No | 29 |
| FY 2008 | LITTLE GOOSE | 1976 | 2021 | 28 | 28 | 7.23% | Yes | No | 28 |
| FY 2008 | LITTLE GOOSE | 1977 | 2021 | 29 | 29 | 7.23% | Yes | No | 29 |
| FY 2008 | LITTLE GOOSE | 1978 | 2021 | 28 | 28 | 7.23% | Yes | No | 28 |
| FY 2008 | LITTLE GOOSE | 1979 | 2021 | 29 | 29 | 7.23% | Yes | No | 29 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2008 | LITTLE GOOSE | 1980 | 2021 | 28 | 28 | 7.23% | Yes | No | 28 |
| FY 2008 | LITTLE GOOSE | 1981 | 2021 | 29 | 29 | 7.23% | Yes | No | 29 |
| FY 2008 | LITTLE GOOSE | 1982 | 2021 | 28 | 28 | 7.23% | Yes | No | 28 |
| FY 2008 | LITTLE GOOSE | 1983 | 2021 | 29 | 29 | 7.23% | Yes | No | 29 |
| FY 2008 | LITTLE GOOSE | 1985 | 2021 | 174 | 174 | 7.23% | No | No | 174 |
| FY 2008 | LITTLE GOOSE | 1986 | 2021 | 239 | 239 | 7.23% | No | No | 239 |
| FY 2008 | LITTLE GOOSE | 1987 | 2021 | 6 | 6 | 7.23% | No | No | 6 |
| FY 2008 | LOWER MONUMENTAL | 1996 | 2021 | 37 | 37 | 7.23% | No | No | 37 |
| FY 2008 | LOWER MONUMENTAL | 1996 | 2021 | 51 | 51 | 7.23% | No | No | 51 |
| **Subtotal** | | | | **$397,887** | **$314,465** | | | | **$277,781** |
| | | | | | | | | | |
| FY 2009 | CONSERVATION | 1989 | 2009 | 40,000 | 40,000 | 8.55% | No | No | 40,000 |
| FY 2009 | BUREAU DIRECT FUND | 2006 | 2009 | 25,000 | 25,000 | 5.05% | No | No | 25,000 |
| FY 2009 | CONSERVATION | 2006 | 2009 | 20,000 | 20,000 | 5.05% | No | No | 20,000 |
| FY 2009 | BPA PROGRAM | 2005 | 2009 | 7,990 | 7,990 | 3.75% | No | No | 7,990 |
| FY 2009 | LITTLE GOOSE | 1971 | 2021 | 42,962 | 36,684 | 7.23% | No | No | 10,075 |
| **Subtotal** | | | | **$135,952** | **$129,674** | | | | **$103,065** |
| | | | | | | | | | |
| FY 2010 | BPA PROGRAM | 2001 | 2010 | 68 | 68 | 6.05% | No | No | 68 |
| FY 2010 | BUREAU DIRECT FUND | 2007 | 2010 | 30,000 | 30,000 | 5.35% | No | No | 30,000 |
| FY 2010 | CONSERVATION | 2007 | 2010 | 20,000 | 20,000 | 5.35% | No | No | 20,000 |
| FY 2010 | FISH, WILDLIFE | 2007 | 2010 | 30,000 | 30,000 | 5.35% | No | No | 30,000 |
| FY 2010 | BUREAU DIRECT FUND | 2007 | 2010 | 35,000 | 35,000 | 5.10% | No | No | 35,000 |
| FY 2010 | FISH, WILDLIFE | 2006 | 2010 | 20,000 | 20,000 | 4.95% | No | No | 20,000 |
| FY 2010 | BPA PROGRAM | 2006 | 2010 | 9,681 | 9,681 | 4.95% | No | No | 9,681 |
| FY 2010 | JOHN DAY | 1971 | 2021 | 34,974 | 34,974 | 7.23% | No | No | 34,974 |
| FY 2010 | LITTLE GOOSE | 1971 | 2021 | 42,962 | 26,609 | 7.23% | No | No | 26,609 |
| FY 2010 | BONNEVILLE | 1997 | 2022 | 122 | 122 | 7.23% | No | No | 88 |
| FY 2010 | ICE HARBOR | 1997 | 2022 | 66 | 66 | 7.23% | No | No | 66 |
| FY 2010 | JOHN DAY | 1997 | 2022 | 133 | 133 | 7.23% | No | No | 133 |
| FY 2010 | LIBBY | 1997 | 2022 | 432 | 432 | 7.23% | No | No | 432 |
| **Subtotal** | | | | **$223,438** | **$207,085** | | | | **$207,051** |
| | | | | | | | | | |
| FY 2011 | BUREAU DIRECT FUND | 1998 | 2011 | 25,000 | 25,000 | 4.74% | No | Yes | 25,000 |
| FY 2011 | BUREAU DIRECT FUND | 2005 | 2011 | 20,000 | 20,000 | 4.74% | No | Yes | 20,000 |
| FY 2011 | FISH, WILDLIFE | 2007 | 2011 | 20,000 | 20,000 | 4.70% | No | No | 20,000 |
| FY 2011 | BUREAU DIRECT FUND | 2008 | 2011 | 35,000 | 35,000 | 3.36% | No | No | 35,000 |
| FY 2011 | BUREAU DIRECT FUND | 2008 | 2011 | 35,000 | 35,000 | 2.85% | No | No | 35,000 |
| FY 2011 | BONNEVILLE | 1997 | 2022 | 122 | 34 | 7.23% | No | No | 34 |
| FY 2011 | JOHN DAY | 1972 | 2022 | 11,502 | 11,502 | 7.21% | No | No | 11,502 |

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Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2011 | JOHN DAY | 1985 | 2022 | 6,490 | 6,490 | 7.21% | No | No | 6,490 |
| FY 2011 | JOHN DAY | 1986 | 2022 | 3,227 | 3,227 | 7.21% | No | No | 3,227 |
| FY 2011 | JOHN DAY | 1987 | 2022 | 706 | 706 | 7.21% | No | No | 706 |
| FY 2011 | JOHN DAY | 1989 | 2022 | 30 | 30 | 7.21% | No | No | 30 |
| FY 2011 | JOHN DAY | 1990 | 2022 | 37 | 37 | 7.21% | No | No | 37 |
| FY 2011 | JOHN DAY | 1992 | 2022 | 19 | 19 | 7.21% | No | No | 19 |
| FY 2011 | YAKIMA-CHANDLER | 1956 | 2022 | 1,068 | 193 | 7.21% | No | No | 193 |
| FY 2011 | YAKIMA-CHANDLER | 1956 | 2022 | 481 | 216 | 7.21% | No | No | 216 |
| FY 2011 | YAKIMA-CHANDLER | 1959 | 2022 | 1 | 1 | 7.21% | Yes | No | 1 |
| FY 2011 | YAKIMA-CHANDLER | 1960 | 2022 | 1 | 1 | 7.21% | Yes | No | 1 |
| FY 2011 | YAKIMA-CHANDLER | 1961 | 2022 | 1 | 1 | 7.21% | Yes | No | 1 |
| FY 2011 | YAKIMA-CHANDLER | 1986 | 2022 | 456 | 455 | 7.21% | No | No | 455 |
| FY 2011 | DWORSHAK | 1973 | 2023 | 138,443 | 132,996 | 7.19% | No | No | 12,227 |
| FY 2011 | DWORSHAK | 1973 | 2023 | 836 | 803 | 7.19% | No | No | 803 |
| FY 2011 | DWORSHAK | 1974 | 2023 | 515 | 515 | 7.19% | Yes | No | 515 |
| FY 2011 | DWORSHAK | 1974 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1975 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1975 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1976 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1976 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1977 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1977 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1978 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1978 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1979 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1979 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1980 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1980 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1981 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1981 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1982 | 2023 | 518 | 518 | 7.19% | Yes | No | 518 |
| FY 2011 | DWORSHAK | 1982 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1983 | 2023 | 523 | 523 | 7.19% | Yes | No | 523 |
| FY 2011 | DWORSHAK | 1983 | 2023 | 3 | 3 | 7.19% | Yes | No | 3 |
| FY 2011 | DWORSHAK | 1985 | 2023 | 1,141 | 1,141 | 7.19% | No | No | 1,141 |
| FY 2011 | DWORSHAK | 1986 | 2023 | 197 | 197 | 7.19% | No | No | 197 |
| FY 2011 | DWORSHAK | 1987 | 2023 | 36 | 5 | 7.19% | No | No | 5 |
| FY 2011 | THE DALLES | 1973 | 2023 | 21,983 | 21,983 | 7.19% | No | No | 21,983 |
| **Subtotal** | | | | **$326,989** | **$320,249** | | | | **$199,480** |

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Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2012 | HILLS CREEK | 1962 | 2012 | 10,353 | 5,159 | 7.16% | No | No | 5,159 |
| FY 2012 | HILLS CREEK | 1974 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | HILLS CREEK | 1977 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | HILLS CREEK | 1978 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | HILLS CREEK | 1979 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | HILLS CREEK | 1980 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | HILLS CREEK | 1981 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | HILLS CREEK | 1982 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | HILLS CREEK | 1983 | 2012 | 13 | 13 | 7.16% | Yes | No | 13 |
| FY 2012 | ICE HARBOR | 1973 | 2012 | 1 | 1 | 7.16% | Yes | No | 1 |
| FY 2012 | BUREAU DIRECT FUND | 2005 | 2012 | 30,000 | 30,000 | 4.81% | No | Yes | 30,000 |
| FY 2012 | BUREAU DIRECT FUND | 2008 | 2012 | 35,000 | 35,000 | 4.00% | No | No | 35,000 |
| FY 2012 | BPA PROGRAM | 2008 | 2012 | 10,000 | 10,000 | 3.20% | No | No | 10,000 |
| FY 2012 | DWORSHAK | 1973 | 2023 | 138,443 | 120,769 | 7.19% | No | No | 56,178 |
| **Subtotal** | | | | **$223,901** | **$201,033** | - | | | **$136,442** |
| | | | | | | | | | |
| FY 2013 | FISH, WILDLIFE | 1998 | 2013 | 60,000 | 60,000 | 6.10% | No | No | 60,000 |
| FY 2013 | CONSERVATION | 2008 | 2013 | 20,000 | 20,000 | 5.82% | No | No | 20,000 |
| FY 2013 | CONSERVATION | 1998 | 2013 | 52,800 | 52,800 | 5.60% | No | No | 52,800 |
| FY 2013 | DWORSHAK | 1973 | 2023 | 138,443 | 64,590 | 7.19% | No | No | 7,716 |
| **Subtotal** | | | | **$271,243** | **$197,390** | | | | **$140,516** |
| | | | | | | | | | |
| FY 2014 | BPA PROGRAM | 1999 | 2014 | 950 | 950 | 5.90% | No | No | 950 |
| FY 2014 | CONSERVATION | 2009 | 2014 | 27,200 | 27,200 | 5.80% | No | No | 27,200 |
| FY 2014 | CONSERVATION | 1998 | 2014 | 37,700 | 37,700 | 5.54% | No | Yes | 37,700 |
| FY 2014 | DWORSHAK | 1973 | 2023 | 138,443 | 56,875 | 7.19% | No | No | 56,875 |
| FY 2014 | THE DALLES | 1974 | 2024 | 7,268 | 7,268 | 7.17% | No | No | 7,268 |
| FY 2014 | LOWER GRANITE | 1975 | 2025 | 119,237 | 117,645 | 7.16% | No | No | 7,353 |
| FY 2014 | LOWER GRANITE | 1976 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1977 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1978 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1979 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1980 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1981 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1982 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1983 | 2025 | 510 | 510 | 7.16% | Yes | No | 510 |
| FY 2014 | LOWER GRANITE | 1985 | 2025 | 328 | 328 | 7.16% | No | No | 328 |
| FY 2014 | LOWER GRANITE | 1986 | 2025 | 215 | 215 | 7.16% | No | No | 215 |
| FY 2014 | LOWER GRANITE | 1987 | 2025 | 8 | 8 | 7.16% | No | No | 8 |
| FY 2014 | LOWER GRANITE | 1995 | 2025 | 96 | 96 | 7.16% | No | No | 96 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| **Subtotal** | | | | **$335,525** | **$252,365** | | | | **$142,073** |
| FY 2015 | CONSERVATION | 2010 | 2015 | 47,600 | 47,600 | 5.99% | No | No | 47,600 |
| FY 2015 | LOWER GRANITE | 1975 | 2025 | 119,237 | 110,292 | 7.16% | No | No | 53,169 |
| **Subtotal** | | | | **$166,837** | **$157,892** | | | | **$100,769** |
| FY 2016 | CONSERVATION | 2011 | 2016 | 47,600 | 47,600 | 6.04% | No | No | 47,600 |
| **Subtotal** | | | | **$47,600** | **$47,600** | | | | **$47,600** |
| FY 2017 | CONSERVATION | 2012 | 2017 | 47,600 | 47,600 | 6.04% | No | No | 47,600 |
| **Subtotal** | | | | **$47,600** | **$47,600** | | | | **$47,600** |
| FY 2018 | CONSERVATION | 2013 | 2018 | 47,600 | 47,600 | 6.04% | No | No | 47,600 |
| FY 2018 | COLUMBIA BASIN - 3RD PWR HOUSE | 1975 | 2025 | 47,328 | 36,690 | 7.16% | No | No | 25,635 |
| FY 2018 | COLUMBIA BASIN - 3RD PWR HOUSE | 1975 | 2025 | 8,702 | 7,435 | 7.16% | No | No | 7,435 |
| FY 2018 | LIBBY | 1975 | 2025 | 54,644 | 48,138 | 7.16% | No | No | 48,138 |
| FY 2018 | LOWER GRANITE | 1975 | 2025 | 119,237 | 57,124 | 7.16% | No | No | 57,124 |
| **Subtotal** | | | | **$277,511** | **$196,987** | | | | **$185,932** |
| FY 2019 | FISH, WILDLIFE | 2005 | 2019 | 20,000 | 20,000 | 5.26% | No | Yes | 20,000 |
| FY 2019 | COLUMBIA BASIN - 3RD PWR HOUSE | 1975 | 2025 | 47,328 | 11,055 | 7.16% | No | No | 11,055 |
| FY 2019 | COLUMBIA BASIN - 3RD PWR HOUSE | 1976 | 2026 | 41,330 | 41,330 | 7.15% | No | No | 41,330 |
| FY 2019 | COLUMBIA BASIN - 3RD PWR HOUSE | 1976 | 2026 | 8,037 | 8,037 | 7.15% | No | No | 8,037 |
| FY 2019 | COLUMBIA BASIN | 1996 | 2026 | 72 | 72 | 7.15% | No | No | 72 |
| FY 2019 | ICE HARBOR | 1976 | 2026 | 20,472 | 20,472 | 7.15% | No | No | 20,472 |
| FY 2019 | ICE HARBOR | 1976 | 2026 | 228 | 228 | 7.15% | No | No | 228 |
| FY 2019 | ICE HARBOR | 1985 | 2026 | 21 | 21 | 7.15% | No | No | 21 |
| FY 2019 | LIBBY | 1976 | 2026 | 153,432 | 153,432 | 7.15% | No | No | 153,432 |
| FY 2019 | LIBBY | 1977 | 2026 | 1,465 | 1,465 | 7.15% | Yes | No | 1,465 |
| FY 2019 | LIBBY | 1978 | 2026 | 1,465 | 1,465 | 7.15% | Yes | No | 1,465 |
| FY 2019 | LIBBY | 1979 | 2026 | 1,465 | 1,465 | 7.15% | Yes | No | 1,465 |
| FY 2019 | LIBBY | 1980 | 2026 | 1,465 | 1,465 | 7.15% | Yes | No | 1,465 |
| FY 2019 | LIBBY | 1981 | 2026 | 1,465 | 1,465 | 7.15% | Yes | No | 1,465 |
| FY 2019 | LIBBY | 1982 | 2026 | 1,465 | 1,465 | 7.15% | Yes | No | 1,465 |
| FY 2019 | LIBBY | 1983 | 2026 | 1,465 | 1,465 | 7.15% | Yes | No | 1,465 |
| FY 2019 | LIBBY | 1985 | 2026 | 518 | 518 | 7.15% | No | No | 518 |
| FY 2019 | LIBBY | 1986 | 2026 | 283 | 283 | 7.15% | No | No | 283 |
| FY 2019 | LIBBY | 1987 | 2026 | 2 | 2 | 7.15% | No | No | 2 |
| FY 2019 | LIBBY | 1989 | 2026 | 1 | 1 | 7.15% | No | No | 1 |
| FY 2019 | MCNARY | 1996 | 2026 | 74 | 74 | 7.15% | No | No | 74 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2019 | MCNARY | 1996 | 2026 | 277 | 277 | 7.15% | No | No | 277 |
| FY 2019 | CHIEF JOSEPH | 1977 | 2027 | 30,512 | 30,512 | 7.15% | No | No | 30,512 |
| FY 2019 | BONNEVILLE | 1977 | 2027 | 15,670 | 15,670 | 7.15% | No | No | 15,670 |
| FY 2019 | COLUMBIA BASIN - 3RD PWR HOUSE | 1977 | 2027 | 42,764 | 42,764 | 7.15% | No | No | 42,764 |
| FY 2019 | COLUMBIA BASIN - 3RD PWR HOUSE | 1977 | 2027 | 7,964 | 7,964 | 7.15% | No | No | 7,964 |
| FY 2019 | LOST CREEK | 1977 | 2027 | 13,505 | 13,413 | 7.15% | No | No | 13,413 |
| FY 2019 | LOST CREEK | 1978 | 2027 | 58 | 58 | 7.15% | Yes | No | 58 |
| FY 2019 | LOST CREEK | 1979 | 2027 | 60 | 60 | 7.15% | Yes | No | 60 |
| FY 2019 | LOST CREEK | 1980 | 2027 | 60 | 60 | 7.15% | Yes | No | 60 |
| FY 2019 | LOST CREEK | 1981 | 2027 | 60 | 60 | 7.15% | Yes | No | 60 |
| FY 2019 | LOST CREEK | 1982 | 2027 | 60 | 60 | 7.15% | Yes | No | 60 |
| FY 2019 | LOST CREEK | 1983 | 2027 | 60 | 60 | 7.15% | Yes | No | 60 |
| FY 2019 | LOST CREEK | 1985 | 2027 | 12 | 12 | 7.15% | No | No | 12 |
| FY 2019 | LOST CREEK | 1986 | 2027 | 6 | 6 | 7.15% | No | No | 6 |
| FY 2019 | LOST CREEK | 1987 | 2027 | 4 | 4 | 7.15% | No | No | 4 |
| FY 2019 | CHIEF JOSEPH | 1978 | 2028 | 75,669 | 75,669 | 7.15% | No | No | 75,669 |
| FY 2019 | COLUMBIA BASIN - 3RD PWR HOUSE | 1978 | 2028 | 42,399 | 42,399 | 7.15% | No | No | 42,399 |
| FY 2019 | COLUMBIA BASIN - 3RD PWR HOUSE | 1978 | 2028 | 7,896 | 7,896 | 7.15% | No | No | 7,896 |
| FY 2019 | LITTLE GOOSE | 1978 | 2028 | 49,578 | 49,578 | 7.15% | No | No | 49,578 |
| FY 2019 | LITTLE GOOSE | 1985 | 2028 | 47 | 47 | 7.15% | No | No | 47 |
| FY 2019 | LOWER GRANITE | 1978 | 2028 | 40,611 | 40,611 | 7.15% | No | No | 40,611 |
| FY 2019 | CHIEF JOSEPH | 1985 | 2029 | 16,372 | 16,372 | 7.15% | No | No | 16,372 |
| FY 2019 | CHIEF JOSEPH | 1986 | 2029 | 5,363 | 5,363 | 7.15% | No | No | 5,363 |
| FY 2019 | CHIEF JOSEPH | 1987 | 2029 | 3,036 | 3,036 | 7.15% | No | No | 3,036 |
| FY 2019 | CHIEF JOSEPH | 1988 | 2029 | 2,722 | 2,722 | 7.15% | No | No | 2,722 |
| FY 2019 | CHIEF JOSEPH | 1989 | 2029 | 2,227 | 2,227 | 7.15% | No | No | 2,227 |
| FY 2019 | CHIEF JOSEPH | 1990 | 2029 | 4,505 | 4,505 | 7.15% | No | No | 4,505 |
| FY 2019 | LIBBY | 1994 | 2029 | 286 | 152 | 7.15% | No | No | 152 |
| FY 2019 | LOWER GRANITE | 1994 | 2029 | 3,543 | 1,551 | 7.15% | No | No | 1,551 |
| FY 2019 | LOWER MONUMENTAL | 1979 | 2029 | 40,669 | 40,669 | 7.15% | No | No | 31,355 |
| FY 2019 | LOWER MONUMENTAL | 1985 | 2029 | 256 | 256 | 7.15% | No | No | 256 |
| **Subtotal** | | | | **$708,304** | **$669,813** | | | | **$660,499** |
| | | | | | | | | | |
| FY 2020 | CHIEF JOSEPH | 1979 | 2029 | 60,079 | 60,079 | 7.15% | No | No | 60,079 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1979 | 2029 | 84,118 | 84,118 | 7.15% | No | No | 84,118 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1979 | 2029 | 15,666 | 15,666 | 7.15% | No | No | 15,666 |
| FY 2020 | LOWER MONUMENTAL | 1979 | 2029 | 40,669 | 9,314 | 7.15% | No | No | 9,314 |
| FY 2020 | DWORSHAK | 1995 | 2030 | 218 | 218 | 7.15% | No | No | 218 |
| FY 2020 | HUNGRY HORSE | 1995 | 2030 | 536 | 536 | 7.15% | Yes | No | 536 |
| FY 2020 | HUNGRY HORSE | 1995 | 2030 | 1,198 | 1,195 | 7.15% | Yes | No | 1,195 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2020 | LIBBY | 1995 | 2030 | 15 | 15 | 7.15% | Yes | No | 15 |
| FY 2020 | LIBBY | 1995 | 2030 | 41 | 41 | 7.15% | No | No | 41 |
| FY 2020 | LIBBY | 1995 | 2030 | 94 | 94 | 7.15% | Yes | No | 94 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1981 | 2031 | 40,964 | 40,964 | 7.15% | No | No | 40,964 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1981 | 2031 | 455 | 455 | 7.15% | No | No | 455 |
| FY 2020 | CHIEF JOSEPH | 1996 | 2031 | 27 | 27 | 7.15% | Yes | No | 27 |
| FY 2020 | BONNEVILLE | 1996 | 2031 | 22 | 22 | 7.15% | No | No | 22 |
| FY 2020 | COLUMBIA BASIN | 1996 | 2031 | 109 | 109 | 7.15% | No | No | 109 |
| FY 2020 | COLUMBIA BASIN | 1996 | 2031 | 251 | 251 | 7.15% | No | No | 251 |
| FY 2020 | DWORSHAK | 1996 | 2031 | 6 | 6 | 7.15% | No | No | 6 |
| FY 2020 | DWORSHAK | 1996 | 2031 | 203 | 203 | 7.15% | No | No | 203 |
| FY 2020 | ICE HARBOR | 1996 | 2031 | 78 | 78 | 7.15% | No | No | 78 |
| FY 2020 | LOST CREEK | 1996 | 2031 | 31 | 31 | 7.15% | No | No | 31 |
| FY 2020 | LOWER GRANITE | 1996 | 2031 | 206 | 206 | 7.15% | No | No | 206 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1982 | 2032 | 203,535 | 203,535 | 7.15% | No | No | 203,535 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1982 | 2032 | 2,264 | 2,264 | 7.15% | No | No | 2,264 |
| FY 2020 | CHIEF JOSEPH | 1997 | 2032 | 166 | 166 | 7.15% | No | No | 166 |
| FY 2020 | BONNEVILLE | 1997 | 2032 | 518 | 518 | 7.15% | No | No | 518 |
| FY 2020 | MCNARY | 1997 | 2032 | 30 | 30 | 7.15% | No | No | 30 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1983 | 2033 | 62,409 | 62,409 | 7.15% | No | No | 3,349 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1983 | 2033 | 694 | 694 | 7.15% | No | No | 694 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1985 | 2033 | 9,138 | 9,138 | 7.15% | No | No | 9,138 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1986 | 2033 | 30,578 | 30,578 | 7.15% | No | No | 30,578 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1987 | 2033 | 2,801 | 2,801 | 7.15% | No | No | 2,801 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1988 | 2033 | 1,271 | 1,271 | 7.15% | No | No | 1,271 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1989 | 2033 | 1,232 | 1,232 | 7.15% | No | No | 1,232 |
| FY 2020 | BONNEVILLE - 2ND POWER HOUSE | 1990 | 2033 | 1,588 | 1,588 | 7.15% | No | No | 1,588 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1983 | 2033 | 712 | 712 | 7.15% | No | No | 712 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1983 | 2033 | 13,003 | 13,003 | 7.15% | No | No | 13,003 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1984 | 2033 | 16,965 | 16,965 | 7.15% | No | No | 16,965 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1984 | 2033 | 13,192 | 13,192 | 7.15% | No | No | 13,192 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1984 | 2033 | 3,160 | 3,160 | 7.15% | No | No | 3,160 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1985 | 2033 | 2,060 | 2,060 | 7.15% | No | No | 2,060 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1985 | 2033 | 41,772 | 41,772 | 7.15% | No | No | 41,772 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1985 | 2033 | 107 | 107 | 7.15% | No | No | 107 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1986 | 2033 | 1,851 | 1,851 | 7.15% | No | No | 1,851 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1986 | 2033 | 15,538 | 15,538 | 7.15% | No | No | 15,538 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1987 | 2033 | 1,730 | 1,730 | 7.15% | No | No | 1,730 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1987 | 2033 | 14,439 | 14,439 | 7.15% | No | No | 14,439 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1988 | 2033 | 2,294 | 2,294 | 7.15% | No | No | 2,294 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1988 | 2033 | 4,351 | 4,351 | 7.15% | No | No | 4,351 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1989 | 2033 | 10,902 | 10,902 | 7.15% | No | No | 10,902 |
| FY 2020 | COLUMBIA BASIN - 3RD PWR HOUSE | 1990 | 2033 | 6,383 | 6,383 | 7.15% | No | No | 6,383 |
| FY 2020 | LOWER SNAKE F AND W | 1983 | 2033 | 30,983 | 9,967 | 7.15% | No | No | 9,967 |
| **Subtotal** | | | | **$740,652** | **$688,278** | | | | **$629,218** |
| FY 2021 | BONNEVILLE - 2ND POWER HOUSE | 1983 | 2033 | 62,409 | 59,060 | 7.15% | No | No | 59,060 |
| FY 2021 | JOHN DAY | 1995 | 2035 | 22 | 22 | 7.15% | No | No | 22 |
| FY 2021 | JOHN DAY | 1995 | 2035 | 52 | 52 | 7.15% | No | No | 52 |
| FY 2021 | JOHN DAY | 1995 | 2035 | 121 | 121 | 7.15% | No | No | 121 |
| FY 2021 | LOWER SNAKE F AND W | 1985 | 2035 | 47,921 | 47,921 | 7.15% | No | No | 47,921 |
| FY 2021 | LOWER MONUMENTAL | 1996 | 2036 | 264 | 264 | 7.15% | Yes | No | 264 |
| FY 2021 | LOWER SNAKE F AND W | 1987 | 2037 | 72,536 | 72,536 | 7.15% | No | No | 72,536 |
| FY 2021 | LIBBY | 1988 | 2038 | 18,043 | 14,781 | 7.15% | No | No | 14,781 |
| FY 2021 | LOWER SNAKE F AND W | 1988 | 2038 | 805 | 805 | 7.15% | No | No | 805 |
| FY 2021 | LITTLE GOOSE | 1995 | 2040 | 17 | 17 | 7.15% | No | No | 17 |
| FY 2021 | LITTLE GOOSE | 1995 | 2040 | 450 | 450 | 7.15% | No | No | 450 |
| FY 2021 | LITTLE GOOSE | 1995 | 2040 | 733 | 733 | 7.15% | Yes | No | 733 |
| FY 2021 | LOWER SNAKE F AND W | 1990 | 2040 | 1,557 | 1,557 | 7.15% | No | No | 1,557 |
| FY 2021 | ICE HARBOR | 1996 | 2041 | 371 | 371 | 7.15% | Yes | No | 371 |
| FY 2021 | LOWER SNAKE F AND W | 1991 | 2041 | 4,411 | 4,411 | 7.15% | No | No | 4,411 |
| FY 2021 | LOWER SNAKE F AND W | 1993 | 2043 | 71,632 | 71,632 | 7.15% | No | No | 71,632 |
| FY 2021 | BONNEVILLE - 2ND POWER HOUSE | 1994 | 2044 | 5,700 | 5,700 | 7.15% | No | No | 5,700 |
| FY 2021 | CHIEF JOSEPH | 1994 | 2044 | 4,280 | 4,017 | 7.15% | No | No | 4,017 |
| FY 2021 | COLUMBIA BASIN - 3RD PWR HOUSE | 1994 | 2044 | 12,631 | 12,631 | 7.15% | No | No | 12,631 |
| FY 2021 | LOWER SNAKE F AND W | 1994 | 2044 | 4,722 | 4,722 | 7.15% | No | No | 4,722 |
| FY 2021 | BONNEVILLE - 2ND POWER HOUSE | 1995 | 2045 | 3,791 | 3,791 | 7.15% | No | No | 3,791 |
| FY 2021 | CHIEF JOSEPH | 1995 | 2045 | 147 | 147 | 7.15% | No | No | 147 |
| FY 2021 | CHIEF JOSEPH | 1995 | 2045 | 562 | 562 | 7.15% | No | No | 562 |
| FY 2021 | CHIEF JOSEPH | 1995 | 2045 | 712 | 712 | 7.15% | Yes | No | 712 |
| FY 2021 | CHIEF JOSEPH | 1995 | 2045 | 784 | 784 | 7.15% | No | No | 784 |
| FY 2021 | BONNEVILLE | 1995 | 2045 | 243 | 243 | 7.15% | No | No | 243 |
| FY 2021 | BONNEVILLE | 1995 | 2045 | 410 | 410 | 7.15% | Yes | No | 410 |
| FY 2021 | BONNEVILLE | 1995 | 2045 | 440 | 440 | 7.15% | Yes | No | 440 |
| FY 2021 | COLUMBIA BASIN | 1995 | 2045 | 287 | 287 | 7.15% | Yes | No | 287 |
| FY 2021 | COLUMBIA BASIN | 1995 | 2045 | 2,511 | 2,453 | 7.15% | No | No | 2,453 |
| FY 2021 | DETROIT-BIG CLIFF | 1995 | 2045 | 38 | 38 | 7.15% | No | No | 38 |
| FY 2021 | DWORSHAK | 1995 | 2045 | 1,162 | 1,162 | 7.15% | No | No | 1,162 |
| FY 2021 | COLUMBIA RIVER FISH MITIGATION | 1995 | 2045 | 43,343 | 39,282 | 7.15% | No | No | 39,282 |
| FY 2021 | HUNGRY HORSE | 1995 | 2045 | 6,190 | 6,190 | 7.15% | No | No | 6,190 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2021 | JOHN DAY | 1995 | 2045 | 37 | 37 | 7.15% | No | No | 37 |
| FY 2021 | JOHN DAY | 1995 | 2045 | 608 | 608 | 7.15% | No | No | 608 |
| FY 2021 | JOHN DAY | 1995 | 2045 | 7,653 | 7,653 | 7.15% | Yes | No | 7,653 |
| FY 2021 | LOOKOUT POINT-DEXTER | 1995 | 2045 | 80 | 39 | 7.15% | No | No | 39 |
| FY 2021 | LOOKOUT POINT-DEXTER | 1995 | 2045 | 33 | 33 | 7.15% | No | No | 33 |
| FY 2021 | LOST CREEK | 1995 | 2045 | 94 | 94 | 7.15% | No | No | 94 |
| FY 2021 | LOWER MONUMENTAL | 1995 | 2045 | 41 | 41 | 7.15% | No | No | 41 |
| FY 2021 | LOWER MONUMENTAL | 1995 | 2045 | 99 | 99 | 7.15% | No | No | 99 |
| FY 2021 | LOWER MONUMENTAL | 1995 | 2045 | 624 | 624 | 7.15% | No | No | 624 |
| FY 2021 | LOWER MONUMENTAL | 1995 | 2045 | 1,122 | 1,122 | 7.15% | Yes | No | 1,122 |
| FY 2021 | MCNARY | 1995 | 2045 | 16 | 16 | 7.15% | No | No | 16 |
| FY 2021 | ALBENI FALLS | 1995 | 2045 | 443 | 443 | 7.15% | No | No | 443 |
| FY 2021 | ALBENI FALLS | 1995 | 2045 | 531 | 531 | 7.15% | No | No | 531 |
| FY 2021 | ALBENI FALLS | 1995 | 2045 | 1,105 | 1,105 | 7.15% | No | No | 1,105 |
| FY 2021 | BOISE | 1996 | 2046 | 442 | 442 | 7.15% | No | No | 442 |
| FY 2021 | BOISE | 1996 | 2046 | 656 | 656 | 7.15% | No | No | 656 |
| FY 2021 | BONNEVILLE - 2ND POWER HOUSE | 1996 | 2046 | 376 | 376 | 7.15% | No | No | 376 |
| FY 2021 | CHIEF JOSEPH | 1996 | 2046 | 3 | 3 | 7.15% | Yes | No | 3 |
| FY 2021 | CHIEF JOSEPH | 1996 | 2046 | 4 | 4 | 7.15% | Yes | No | 4 |
| FY 2021 | CHIEF JOSEPH | 1996 | 2046 | 355 | 355 | 7.15% | No | No | 355 |
| FY 2021 | CHIEF JOSEPH | 1996 | 2046 | 729 | 729 | 7.15% | No | No | 729 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 18 | 18 | 7.15% | No | No | 18 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 18 | 18 | 7.15% | No | No | 18 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 80 | 80 | 7.15% | No | No | 80 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 109 | 109 | 7.15% | No | No | 109 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 142 | 142 | 7.15% | No | No | 142 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 223 | 223 | 7.15% | No | No | 223 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 751 | 751 | 7.15% | No | No | 751 |
| FY 2021 | BONNEVILLE | 1996 | 2046 | 1,322 | 1,322 | 7.15% | Yes | No | 1,322 |
| FY 2021 | COLUMBIA BASIN | 1996 | 2046 | 426 | 426 | 7.15% | No | No | 426 |
| FY 2021 | COLUMBIA BASIN | 1996 | 2046 | 368 | 368 | 7.15% | No | No | 368 |
| FY 2021 | GREEN PETER-FOSTER | 1996 | 2046 | 26 | 26 | 7.15% | No | No | 26 |
| FY 2021 | DWORSHAK | 1996 | 2046 | 3 | 3 | 7.15% | Yes | No | 3 |
| FY 2021 | DWORSHAK | 1996 | 2046 | 4 | 4 | 7.15% | Yes | No | 4 |
| FY 2021 | DWORSHAK | 1996 | 2046 | 46 | 46 | 7.15% | No | No | 46 |
| FY 2021 | COLUMBIA RIVER FISH MITIGATION | 1996 | 2046 | 2,431 | 2,431 | 7.15% | No | No | 2,431 |
| FY 2021 | HILLS CREEK | 1996 | 2046 | 28 | 28 | 7.15% | No | No | 28 |
| FY 2021 | HUNGRY HORSE | 1996 | 2046 | 15 | 15 | 7.15% | No | No | 15 |
| FY 2021 | HUNGRY HORSE | 1996 | 2046 | 2 | 2 | 7.15% | No | No | 2 |
| FY 2021 | LITTLE GOOSE | 1996 | 2046 | 10 | 10 | 7.15% | No | No | 10 |

Bonneville Power Administration
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Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2021 | LITTLE GOOSE | 1996 | 2046 | 10 | 10 | 7.15% | No | No | 10 |
| FY 2021 | LITTLE GOOSE | 1996 | 2046 | 211 | 211 | 7.15% | No | No | 211 |
| FY 2021 | LITTLE GOOSE | 1996 | 2046 | 241 | 241 | 7.15% | No | No | 241 |
| FY 2021 | LITTLE GOOSE | 1996 | 2046 | 520 | 520 | 7.15% | Yes | No | 520 |
| FY 2021 | LITTLE GOOSE | 1996 | 2046 | 3,909 | 3,909 | 7.15% | Yes | No | 3,909 |
| FY 2021 | LOST CREEK | 1996 | 2046 | 24 | 24 | 7.15% | No | No | 24 |
| FY 2021 | LOWER GRANITE | 1996 | 2046 | 9 | 9 | 7.15% | Yes | No | 9 |
| FY 2021 | LOWER GRANITE | 1996 | 2046 | 625 | 625 | 7.15% | No | No | 625 |
| FY 2021 | LOWER MONUMENTAL | 1996 | 2046 | 10 | 10 | 7.15% | No | No | 10 |
| FY 2021 | LOWER SNAKE F AND W | 1996 | 2046 | 12,085 | 12,085 | 7.15% | No | No | 12,085 |
| FY 2021 | MCNARY | 1996 | 2046 | 619 | 619 | 7.15% | No | No | 619 |
| FY 2021 | THE DALLES | 1996 | 2046 | 1,991 | 1,991 | 7.15% | No | No | 1,991 |
| FY 2021 | BOISE | 1997 | 2047 | 2,272 | 2,272 | 7.15% | No | No | 2,272 |
| FY 2021 | CHIEF JOSEPH | 1997 | 2047 | 657 | 657 | 7.15% | No | No | 657 |
| FY 2021 | BONNEVILLE | 1997 | 2047 | 161 | 161 | 7.15% | No | No | 161 |
| FY 2021 | COUGAR | 1997 | 2047 | 26 | 26 | 7.15% | No | No | 26 |
| FY 2021 | COLUMBIA BASIN | 1997 | 2047 | 3,393 | 3,393 | 7.15% | No | No | 3,393 |
| FY 2021 | DWORSHAK | 1997 | 2047 | 7,588 | 7,588 | 7.15% | No | No | 7,588 |
| FY 2021 | HUNGRY HORSE | 1997 | 2047 | 216 | 216 | 7.15% | No | No | 216 |
| FY 2021 | ICE HARBOR | 1997 | 2047 | 67 | 67 | 7.15% | No | No | 67 |
| FY 2021 | JOHN DAY | 1997 | 2047 | 179 | 179 | 7.15% | No | No | 179 |
| FY 2021 | LIBBY | 1997 | 2047 | 660 | 660 | 7.15% | No | No | 660 |
| FY 2021 | LITTLE GOOSE | 1997 | 2047 | 1 | 1 | 7.15% | No | No | 1 |
| FY 2021 | LOWER GRANITE | 1997 | 2047 | 677 | 677 | 7.15% | No | No | 677 |
| FY 2021 | LOWER SNAKE F AND W | 1997 | 2047 | 2,173 | 2,173 | 7.15% | No | No | 2,173 |
| FY 2021 | MINIDOKA | 1997 | 2047 | 50,911 | 50,911 | 7.15% | No | No | 50,911 |
| FY 2021 | ALBENI FALLS | 1997 | 2047 | 431 | 431 | 7.15% | No | No | 431 |
| FY 2021 | BUREAU DIRECT FUND | 2012 | 2057 | 178,500 | 178,500 | 6.90% | No | No | 178,500 |
| FY 2021 | BUREAU DIRECT FUND | 2013 | 2058 | 188,700 | 188,700 | 6.90% | No | No | 19,789 |
| **Subtotal** | | | | **$847,236** | **$836,201** | | | | **$667,290** |
| | | | | | | | | | |
| FY 2022 | BONNEVILLE | 1997 | 2022 | 122 | - | 7.23% | No | No | - |
| FY 2022 | BUREAU DIRECT FUND | 2013 | 2058 | 188,700 | 168,912 | 6.90% | No | No | 168,912 |
| FY 2022 | ALBENI FALLS | 2014 | 2059 | 121,700 | 121,700 | 6.73% | Yes | No | 121,700 |
| FY 2022 | ALBENI FALLS | 2015 | 2060 | 122,165 | 122,165 | 6.73% | Yes | No | 122,165 |
| FY 2022 | ALBENI FALLS | 2016 | 2061 | 122,627 | 122,627 | 6.73% | Yes | No | 122,627 |
| FY 2022 | ALBENI FALLS | 2017 | 2062 | 123,162 | 123,162 | 6.73% | Yes | No | 123,162 |
| FY 2022 | ALBENI FALLS | 2018 | 2063 | 123,768 | 123,768 | 6.73% | Yes | No | 47,089 |
| **Subtotal** | | | | **$802,244** | **$782,334** | | | | **$705,655** |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2023 | FISH, WILDLIFE | 2008 | 2023 | 25,000 | 25,000 | 5.82% | No | No | 25,000 |
| FY 2023 | BPA PROGRAM | 2011 | 2046 | 14,950 | 14,950 | 6.90% | No | No | 14,950 |
| FY 2023 | BPA PROGRAM | 2012 | 2047 | 15,041 | 15,041 | 6.90% | No | No | 15,041 |
| FY 2023 | BPA PROGRAM | 2013 | 2048 | 15,099 | 15,099 | 6.90% | No | No | 8,466 |
| FY 2023 | ALBENI FALLS | 2018 | 2063 | 123,768 | 76,679 | 6.73% | Yes | No | 76,679 |
| FY 2023 | ALBENI FALLS | 2019 | 2064 | 124,442 | 124,442 | 6.73% | Yes | No | 124,442 |
| FY 2023 | ALBENI FALLS | 2020 | 2065 | 125,175 | 125,175 | 6.73% | Yes | No | 125,175 |
| FY 2023 | ALBENI FALLS | 2021 | 2066 | 125,969 | 125,969 | 6.73% | Yes | No | 125,969 |
| FY 2023 | ALBENI FALLS | 2022 | 2067 | 126,816 | 126,816 | 6.73% | Yes | No | 126,816 |
| FY 2023 | ALBENI FALLS | 2023 | 2068 | 112,884 | 112,884 | 6.73% | Yes | No | 112,884 |
| **Subtotal** | | | | **$809,144** | **$762,055** | | | | **$755,422** |
| FY 2024 | FISH, WILDLIFE | 2009 | 2024 | 50,000 | 50,000 | 6.23% | No | No | 50,000 |
| FY 2024 | BPA PROGRAM | 2009 | 2044 | 16,500 | 12,714 | 6.63% | No | No | 12,714 |
| FY 2024 | BPA PROGRAM | 2010 | 2045 | 13,871 | 13,871 | 6.85% | No | No | 13,871 |
| FY 2024 | BPA PROGRAM | 2013 | 2048 | 15,099 | 6,633 | 6.90% | No | No | 6,633 |
| FY 2024 | BONNEVILLE | 2000 | 2050 | 24,446 | 24,446 | 6.13% | No | No | 22,288 |
| FY 2024 | COLUMBIA RIVER FISH MITIGATION | 2000 | 2050 | 47,006 | 47,006 | 6.13% | No | No | 47,006 |
| FY 2024 | HILLS CREEK | 2000 | 2050 | 2,630 | 2,630 | 6.13% | No | No | 2,630 |
| FY 2024 | ICE HARBOR | 2000 | 2050 | 548 | 548 | 6.13% | No | No | 548 |
| FY 2024 | JOHN DAY | 2000 | 2050 | 2,761 | 2,761 | 6.13% | No | No | 2,761 |
| FY 2024 | LOOKOUT POINT-DEXTER | 2000 | 2050 | 5,098 | 5,098 | 6.13% | No | No | 5,098 |
| FY 2024 | LOWER SNAKE F AND W | 2000 | 2050 | 1,529 | 1,529 | 6.13% | No | No | 1,529 |
| FY 2024 | THE DALLES | 2000 | 2050 | 2,588 | 2,588 | 6.13% | No | No | 2,588 |
| FY 2024 | BUREAU DIRECT FUND | 2009 | 2054 | 133,238 | 133,238 | 6.63% | No | No | 133,238 |
| FY 2024 | BUREAU DIRECT FUND | 2010 | 2055 | 157,250 | 157,250 | 6.63% | No | No | 157,250 |
| FY 2024 | BUREAU DIRECT FUND | 2011 | 2056 | 170,850 | 170,850 | 6.85% | No | No | 170,850 |
| FY 2024 | ALBENI FALLS | 2024 | 2069 | 100,653 | 100,653 | 6.73% | Yes | No | 100,653 |
| **Subtotal** | | | | **$744,068** | **$731,816** | | | | **$729,658** |
| FY 2025 | FISH, WILDLIFE | 2010 | 2025 | 70,000 | 70,000 | 6.45% | No | No | 70,000 |
| FY 2025 | FISH, WILDLIFE | 2011 | 2026 | 60,000 | 60,000 | 6.50% | No | No | 60,000 |
| FY 2025 | FISH, WILDLIFE | 2012 | 2027 | 50,000 | 50,000 | 6.50% | No | No | 50,000 |
| FY 2025 | FISH, WILDLIFE | 2013 | 2028 | 50,000 | 50,000 | 6.50% | No | No | 50,000 |
| FY 2025 | BPA PROGRAM | 2008 | 2043 | 10,000 | 10,000 | 6.15% | No | No | 10,000 |
| FY 2025 | BUREAU DIRECT FUND | 2008 | 2048 | 45,000 | 45,000 | 6.15% | No | No | 45,000 |
| FY 2025 | BONNEVILLE | 2000 | 2050 | 24,446 | 2,157 | 6.13% | No | No | 2,157 |
| FY 2025 | COLUMBIA RIVER FISH MITIGATION | 2010 | 2060 | 88,000 | 88,000 | 5.95% | No | No | 35,048 |
| FY 2025 | COLUMBIA RIVER FISH MITIGATION | 2011 | 2061 | 96,000 | 96,000 | 6.00% | No | No | 96,000 |
| FY 2025 | COLUMBIA RIVER FISH MITIGATION | 2012 | 2062 | 50,000 | 50,000 | 6.00% | No | No | 50,000 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2025 | COLUMBIA RIVER FISH MITIGATION | 2013 | 2063 | 124,288 | 124,288 | 6.00% | No | No | 124,288 |
| FY 2025 | ALBENI FALLS | 2025 | 2070 | 89,863 | 89,863 | 6.73% | Yes | No | 89,863 |
| **Subtotal** | | | | **$757,597** | **$735,308** | | | | **$682,356** |
| FY 2026 | COLUMBIA BASIN | 1996 | 2026 | 72 | 0 | 7.15% | No | No | 0 |
| FY 2026 | BONNEVILLE | 1999 | 2049 | 19,368 | 19,368 | 5.38% | No | No | 19,368 |
| FY 2026 | DWORSHAK | 1999 | 2049 | 630 | 630 | 5.38% | No | No | 630 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 1999 | 2049 | 14,115 | 14,115 | 5.38% | No | No | 14,115 |
| FY 2026 | ICE HARBOR | 1999 | 2049 | 5,516 | 5,516 | 5.38% | No | No | 5,516 |
| FY 2026 | JOHN DAY | 1999 | 2049 | 3,510 | 3,510 | 5.38% | No | No | 3,510 |
| FY 2026 | LOWER GRANITE | 1999 | 2049 | 856 | 856 | 5.38% | No | No | 856 |
| FY 2026 | LOWER SNAKE F AND W | 1999 | 2049 | 7 | 7 | 5.38% | No | No | 7 |
| FY 2026 | CHIEF JOSEPH | 2001 | 2051 | 345 | 345 | 5.88% | No | No | 345 |
| FY 2026 | BONNEVILLE | 2001 | 2051 | 2,530 | 2,530 | 5.88% | No | No | 2,530 |
| FY 2026 | COLUMBIA BASIN | 2001 | 2051 | 69,226 | 69,226 | 5.88% | No | No | 69,226 |
| FY 2026 | GREEN PETER-FOSTER | 2001 | 2051 | 200 | 200 | 5.88% | No | No | 200 |
| FY 2026 | DETROIT-BIG CLIFF | 2001 | 2051 | 282 | 282 | 5.88% | No | No | 282 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 2001 | 2051 | 6,168 | 6,168 | 5.88% | No | No | 6,168 |
| FY 2026 | HILLS CREEK | 2001 | 2051 | 8 | 8 | 5.88% | No | No | 8 |
| FY 2026 | HUNGRY HORSE | 2001 | 2051 | 552 | 552 | 5.88% | No | No | 552 |
| FY 2026 | ICE HARBOR | 2001 | 2051 | 764 | 764 | 5.88% | No | No | 764 |
| FY 2026 | JOHN DAY | 2001 | 2051 | 619 | 619 | 5.88% | No | No | 619 |
| FY 2026 | LIBBY | 2001 | 2051 | 5,562 | 5,562 | 5.88% | No | No | 5,562 |
| FY 2026 | LITTLE GOOSE | 2001 | 2051 | 4,608 | 4,608 | 5.88% | No | No | 4,608 |
| FY 2026 | LOST CREEK | 2001 | 2051 | 154 | 154 | 5.88% | No | No | 154 |
| FY 2026 | LOWER GRANITE | 2001 | 2051 | 2,025 | 2,025 | 5.88% | No | No | 2,025 |
| FY 2026 | LOWER MONUMENTAL | 2001 | 2051 | 3,301 | 3,301 | 5.88% | No | No | 3,301 |
| FY 2026 | LOWER SNAKE F AND W | 2001 | 2051 | 325 | 325 | 5.88% | No | No | 325 |
| FY 2026 | MCNARY | 2001 | 2051 | 1,046 | 1,046 | 5.88% | No | No | 1,046 |
| FY 2026 | MINIDOKA | 2001 | 2051 | 61 | 49 | 5.88% | No | No | 49 |
| FY 2026 | UNASSIGNED BOND | 2001 | 2051 | 11,145 | 11,145 | 5.88% | No | No | 11,145 |
| FY 2026 | YAKIMA-ROZA | 2001 | 2051 | 15 | 14 | 5.88% | No | No | 14 |
| FY 2026 | CHIEF JOSEPH | 2002 | 2052 | 2 | 2 | 5.50% | No | No | 2 |
| FY 2026 | BONNEVILLE | 2002 | 2052 | 448 | 448 | 5.50% | No | No | 448 |
| FY 2026 | DETROIT-BIG CLIFF | 2002 | 2052 | 18 | 18 | 5.50% | No | No | 18 |
| FY 2026 | DWORSHAK | 2002 | 2052 | 199 | 199 | 5.50% | No | No | 199 |
| FY 2026 | HILLS CREEK | 2002 | 2052 | 2 | 2 | 5.50% | No | No | 2 |
| FY 2026 | ICE HARBOR | 2002 | 2052 | 1,014 | 1,014 | 5.50% | No | No | 1,014 |
| FY 2026 | LITTLE GOOSE | 2002 | 2052 | 27 | 27 | 5.50% | No | No | 27 |
| FY 2026 | LOWER GRANITE | 2002 | 2052 | 1,275 | 1,275 | 5.50% | No | No | 1,275 |

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| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2026 | LOWER MONUMENTAL | 2002 | 2052 | 29 | 29 | 5.50% | No | No | 29 |
| FY 2026 | LOWER SNAKE F AND W | 2002 | 2052 | 890 | 890 | 5.50% | No | No | 890 |
| FY 2026 | THE DALLES | 2002 | 2052 | 1,226 | 1,226 | 5.50% | No | No | 1,226 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 2002 | 2052 | 8,797 | 8,797 | 5.13% | No | No | 8,797 |
| FY 2026 | MCNARY | 2003 | 2053 | 97 | 97 | 5.75% | No | No | 97 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 2003 | 2053 | 68,440 | 68,440 | 5.13% | No | No | 1,410 |
| FY 2026 | ICE HARBOR | 2003 | 2053 | 50 | 50 | 5.13% | No | No | 50 |
| FY 2026 | LITTLE GOOSE | 2003 | 2053 | 146 | 146 | 5.13% | No | No | 146 |
| FY 2026 | LOOKOUT POINT-DEXTER | 2003 | 2053 | 135 | 135 | 5.13% | No | No | 135 |
| FY 2026 | LOWER GRANITE | 2003 | 2053 | 42 | 42 | 5.13% | No | No | 42 |
| FY 2026 | LOWER MONUMENTAL | 2003 | 2053 | 22 | 22 | 5.13% | No | No | 22 |
| FY 2026 | LOWER SNAKE F AND W | 2003 | 2053 | 98 | 98 | 5.13% | No | No | 98 |
| FY 2026 | BONNEVILLE | 2004 | 2054 | 26,741 | 26,741 | 5.38% | No | No | 26,741 |
| FY 2026 | COUGAR | 2004 | 2054 | 15,748 | 15,748 | 5.38% | No | No | 15,748 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 2004 | 2054 | 60,581 | 60,581 | 5.38% | No | No | 60,581 |
| FY 2026 | ICE HARBOR | 2004 | 2054 | 3,334 | 3,334 | 5.38% | No | No | 3,334 |
| FY 2026 | JOHN DAY | 2004 | 2054 | 2,830 | 2,830 | 5.38% | No | No | 2,830 |
| FY 2026 | LITTLE GOOSE | 2004 | 2054 | 67 | 67 | 5.38% | No | No | 68 |
| FY 2026 | LOWER MONUMENTAL | 2004 | 2054 | 3,423 | 3,423 | 5.38% | No | No | 3,423 |
| FY 2026 | LOWER SNAKE F AND W | 2004 | 2054 | 230 | 230 | 5.38% | No | No | 230 |
| FY 2026 | MCNARY | 2004 | 2054 | 6,138 | 6,138 | 5.38% | No | No | 6,138 |
| FY 2026 | THE DALLES | 2004 | 2054 | 182 | 182 | 5.38% | No | No | 182 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 2008 | 2058 | 184,000 | 184,000 | 5.42% | No | No | 184,000 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 2010 | 2060 | 88,000 | 52,953 | 5.95% | No | No | 52,953 |
| FY 2026 | COLUMBIA RIVER FISH MITIGATION | 2009 | 2060 | 110,000 | 110,000 | 5.73% | No | No | 110,000 |
| FY 2026 | ALBENI FALLS | 2026 | 2071 | 80,352 | 80,352 | 6.73% | Yes | No | 80,352 |
| **Subtotal** | | | | **$817,589** | **$782,456** | | | | **$715,427** |
| | | | | | | | | | |
| FY 2027 | CHIEF JOSEPH | 2003 | 2053 | 992 | 992 | 5.13% | No | No | 992 |
| FY 2027 | BONNEVILLE | 2003 | 2053 | 4,581 | 4,581 | 5.13% | No | No | 4,581 |
| FY 2027 | DETROIT-BIG CLIFF | 2003 | 2053 | 223 | 223 | 5.13% | No | No | 223 |
| FY 2027 | DWORSHAK | 2003 | 2053 | 761 | 761 | 5.13% | No | No | 761 |
| FY 2027 | COLUMBIA RIVER FISH MITIGATION | 2003 | 2053 | 68,440 | 67,030 | 5.13% | No | No | 67,030 |
| FY 2027 | BOISE | 2005 | 2055 | 903 | 903 | 5.13% | No | No | 903 |
| FY 2027 | BONNEVILLE | 2005 | 2055 | 19,725 | 19,725 | 5.13% | No | No | 19,725 |
| FY 2027 | COUGAR | 2005 | 2055 | 35,317 | 35,317 | 5.13% | No | No | 35,317 |
| FY 2027 | COLUMBIA BASIN | 2005 | 2055 | 11,056 | 11,056 | 5.13% | No | No | 11,056 |
| FY 2027 | DETROIT-BIG CLIFF | 2005 | 2055 | 1,031 | 1,031 | 5.13% | No | No | 1,031 |
| FY 2027 | DWORSHAK | 2005 | 2055 | 713 | 713 | 5.13% | No | No | 713 |
| FY 2027 | COLUMBIA RIVER FISH MITIGATION | 2005 | 2055 | 52,039 | 52,039 | 5.13% | No | No | 52,039 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2027 | HILLS CREEK | 2005 | 2055 | 46 | 46 | 5.13% | No | No | 46 |
| FY 2027 | HUNGRY HORSE | 2005 | 2055 | 2,951 | 2,951 | 5.13% | No | No | 2,951 |
| FY 2027 | JOHN DAY | 2005 | 2055 | 2,827 | 2,827 | 5.13% | No | No | 2,828 |
| FY 2027 | LOOKOUT POINT-DEXTER | 2005 | 2055 | 7,355 | 7,355 | 5.13% | No | No | 7,355 |
| FY 2027 | LOWER GRANITE | 2005 | 2055 | 215 | 215 | 5.13% | No | No | 215 |
| FY 2027 | LOWER MONUMENTAL | 2005 | 2055 | 527 | 527 | 5.13% | No | No | 527 |
| FY 2027 | LOWER SNAKE F AND W | 2005 | 2055 | 4 | 4 | 5.13% | No | No | 4 |
| FY 2027 | MCNARY | 2005 | 2055 | 550 | 550 | 5.13% | No | No | 550 |
| FY 2027 | ALBENI FALLS | 2005 | 2055 | 481 | 481 | 5.13% | No | No | 481 |
| FY 2027 | YAKIMA-CHANDLER | 2005 | 2055 | 833 | 833 | 5.13% | No | No | 833 |
| FY 2027 | THE DALLES | 2005 | 2055 | 36,019 | 36,019 | 5.13% | No | No | 36,019 |
| FY 2027 | BOISE | 2006 | 2056 | 15 | 15 | 4.50% | No | No | 15 |
| FY 2027 | BONNEVILLE | 2006 | 2056 | 4,203 | 4,203 | 4.50% | No | No | 4,203 |
| FY 2027 | COUGAR | 2006 | 2056 | 474 | 474 | 4.50% | No | No | 474 |
| FY 2027 | COLUMBIA BASIN | 2006 | 2056 | 3,143 | 3,143 | 4.50% | No | No | 3,143 |
| FY 2027 | DWORSHAK | 2006 | 2056 | 73 | 73 | 4.50% | No | No | 73 |
| FY 2027 | COLUMBIA RIVER FISH MITIGATION | 2006 | 2056 | 360,165 | 360,165 | 4.50% | No | No | 360,165 |
| FY 2027 | JOHN DAY | 2006 | 2056 | 601 | 601 | 4.50% | No | No | 601 |
| FY 2027 | LOWER MONUMENTAL | 2006 | 2056 | 285 | 285 | 4.50% | No | No | 285 |
| FY 2027 | LOWER SNAKE F AND W | 2006 | 2056 | 379 | 379 | 4.50% | No | No | 379 |
| FY 2027 | MCNARY | 2006 | 2056 | 8,169 | 8,169 | 4.50% | No | No | 8,169 |
| FY 2027 | THE DALLES | 2006 | 2056 | 2,597 | 2,597 | 4.50% | No | No | 2,597 |
| FY 2027 | BOISE | 2007 | 2057 | 76 | 76 | 5.00% | No | No | 76 |
| FY 2027 | BONNEVILLE | 2007 | 2057 | 433 | 433 | 5.00% | No | No | 433 |
| FY 2027 | COUGAR | 2007 | 2057 | 521 | 521 | 5.00% | No | No | 521 |
| FY 2027 | COLUMBIA BASIN | 2007 | 2057 | 929 | 929 | 5.00% | No | No | 929 |
| FY 2027 | COLUMBIA RIVER FISH MITIGATION | 2007 | 2057 | 49,410 | 49,410 | 5.00% | No | No | 49,410 |
| FY 2027 | HUNGRY HORSE | 2007 | 2057 | 294 | 294 | 5.00% | No | No | 294 |
| FY 2027 | JOHN DAY | 2007 | 2057 | 205 | 205 | 5.00% | No | No | 205 |
| FY 2027 | LOOKOUT POINT-DEXTER | 2007 | 2057 | 572 | 572 | 5.00% | No | No | 572 |
| FY 2027 | MCNARY | 2007 | 2057 | 33 | 33 | 5.00% | No | No | 33 |
| FY 2027 | MINIDOKA | 2007 | 2057 | 17 | 17 | 5.00% | No | No | 17 |
| FY 2027 | THE DALLES | 2007 | 2057 | 140 | 140 | 5.00% | No | No | 140 |
| FY 2027 | ALBENI FALLS | 2027 | 2072 | 71,974 | 71,974 | 6.73% | Yes | No | 71,974 |
| **Subtotal** | | | | **$752,297** | **$750,887** | | | | **$750,887** |
| | | | | | | | | | |
| FY 2028 | ALBENI FALLS | 2028 | 2073 | 64,513 | 64,513 | 6.73% | Yes | No | 64,513 |
| **Subtotal** | | | | **$64,513** | **$64,513** | | | | **$64,513** |

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| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2029 | ALBENI FALLS | 2029 | 2074 | 57,921 | 57,921 | 6.73% | Yes | No | 57,921 |
| **Subtotal** | | | | **$57,921** | **$57,921** | | | | **$57,921** |
| FY 2030 | ALBENI FALLS | 2030 | 2075 | 52,153 | 52,153 | 6.73% | Yes | No | 52,153 |
| **Subtotal** | | | | **$52,153** | **$52,153** | | | | **$52,153** |
| FY 2031 | BUREAU DIRECT FUND | 2007 | 2031 | 30,000 | 30,000 | 6.57% | No | Yes | 30,000 |
| FY 2031 | ALBENI FALLS | 2031 | 2076 | 47,020 | 47,020 | 6.73% | Yes | No | 47,020 |
| **Subtotal** | | | | **$77,020** | **$77,020** | | | | **$77,020** |
| FY 2032 | ALBENI FALLS | 2032 | 2077 | 42,490 | 42,490 | 6.73% | Yes | No | 42,490 |
| **Subtotal** | | | | **$42,490** | **$42,490** | | | | **$42,490** |
| FY 2033 | BONNEVILLE - 2ND POWER HOUSE | 1983 | 2033 | 62,409 | -0 | 7.15% | No | No | -0 |
| FY 2033 | ALBENI FALLS | 2033 | 2078 | 60,705 | 60,705 | 6.73% | Yes | No | 60,705 |
| **Subtotal** | | | | **$123,114** | **$60,705** | | | | **$60,705** |
| FY 2034 | ALBENI FALLS | 2034 | 2079 | 61,258 | 61,258 | 6.73% | Yes | No | 61,258 |
| **Subtotal** | | | | **$61,258** | **$61,258** | | | | **$61,258** |
| FY 2035 | ALBENI FALLS | 2035 | 2080 | 61,861 | 61,861 | 6.73% | Yes | No | 61,861 |
| **Subtotal** | | | | **$61,861** | **$61,861** | | | | **$61,861** |
| FY 2036 | ALBENI FALLS | 2036 | 2081 | 62,446 | 62,446 | 6.73% | Yes | No | 62,446 |
| **Subtotal** | | | | **$62,446** | **$62,446** | | | | **$62,446** |
| FY 2037 | ALBENI FALLS | 2037 | 2082 | 63,080 | 63,080 | 6.73% | Yes | No | 63,080 |
| **Subtotal** | | | | **$63,080** | **$63,080** | | | | **$63,080** |
| FY 2038 | ALBENI FALLS | 2038 | 2083 | 63,758 | 63,758 | 6.73% | Yes | No | 63,758 |
| **Subtotal** | | | | **$63,758** | **$63,758** | | | | **$63,758** |
| FY 2039 | BUREAU DIRECT FUND | 2006 | 2039 | 45,000 | 45,000 | 6.55% | No | Yes | 45,000 |
| FY 2039 | ALBENI FALLS | 2039 | 2084 | 64,483 | 64,483 | 6.73% | Yes | No | 64,483 |
| **Subtotal** | | | | **$109,483** | **$109,483** | | | | **$109,483** |
| FY 2040 | ALBENI FALLS | 2040 | 2085 | 65,185 | 65,185 | 6.73% | Yes | No | 65,185 |
| **Subtotal** | | | | **$65,185** | **$65,185** | | | | **$65,185** |

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| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2041 | ALBENI FALLS | 2041 | 2086 | 65,929 | 65,929 | 6.73% | Yes | No | 65,929 |
| **Subtotal** | | | | **$65,929** | **$65,929** | | | | **$65,929** |
| FY 2042 | ALBENI FALLS | 2042 | 2087 | 66,715 | 66,715 | 6.73% | Yes | No | 66,715 |
| **Subtotal** | | | | **$66,715** | **$66,715** | | | | **$66,715** |
| FY 2043 | BUREAU DIRECT FUND | 2006 | 2043 | 15,000 | 15,000 | 6.55% | No | Yes | 15,000 |
| FY 2043 | ALBENI FALLS | 2043 | 2088 | 62,853 | 62,853 | 6.73% | Yes | No | 62,853 |
| **Subtotal** | | | | **$77,853** | **$77,853** | | | | **$77,853** |
| FY 2044 | ALBENI FALLS | 2044 | 2089 | 59,219 | 59,219 | 6.73% | Yes | No | 59,219 |
| **Subtotal** | | | | **$59,219** | **$59,219** | | | | **$59,219** |
| FY 2045 | COLUMBIA BASIN | 1995 | 2045 | 287 | 0 | 7.15% | Yes | No | 0 |
| FY 2045 | ALBENI FALLS | 2045 | 2090 | 55,862 | 55,862 | 6.73% | Yes | No | 55,862 |
| **Subtotal** | | | | **$56,149** | **$55,862** | | | | **$55,862** |
| FY 2046 | BOISE | 1996 | 2046 | 442 | 0 | 7.15% | No | No | 0 |
| FY 2046 | ALBENI FALLS | 2046 | 2091 | 52,713 | 52,713 | 6.73% | Yes | No | 52,713 |
| **Subtotal** | | | | **$53,155** | **$52,713** | | | | **$52,713** |
| FY 2047 | BOISE | 1997 | 2047 | 2,272 | 0 | 7.15% | No | No | 0 |
| FY 2047 | MINIDOKA | 1997 | 2047 | 50,911 | 0 | 7.15% | No | No | 0 |
| FY 2047 | ALBENI FALLS | 1997 | 2047 | 431 | -0 | 7.15% | No | No | -0 |
| FY 2047 | BUREAU DIRECT FUND | 2005 | 2047 | 25,000 | 25,000 | 6.00% | No | Yes | 25,000 |
| FY 2047 | ALBENI FALLS | 2047 | 2092 | 49,763 | 49,763 | 6.73% | Yes | No | 49,763 |
| **Subtotal** | | | | **$128,377** | **$74,763** | | | | **$74,763** |
| FY 2048 | ALBENI FALLS | 2048 | 2093 | 47,004 | 47,004 | 6.73% | Yes | No | 47,004 |
| **Subtotal** | | | | **$47,004** | **$47,004** | | | | **$47,004** |
| FY 2049 | BONNEVILLE | 1999 | 2049 | 19,368 | 0 | 5.38% | No | No | 0 |
| FY 2049 | DWORSHAK | 1999 | 2049 | 630 | -0 | 5.38% | No | No | -0 |
| FY 2049 | COLUMBIA RIVER FISH MITIGATION | 1999 | 2049 | 14,115 | 0 | 5.38% | No | No | 0 |
| FY 2049 | ICE HARBOR | 1999 | 2049 | 5,516 | -0 | 5.38% | No | No | -0 |
| FY 2049 | JOHN DAY | 1999 | 2049 | 3,510 | 0 | 5.38% | No | No | 0 |
| FY 2049 | LOWER GRANITE | 1999 | 2049 | 856 | -0 | 5.38% | No | No | -0 |
| FY 2049 | ALBENI FALLS | 2049 | 2094 | 42,410 | 42,410 | 6.73% | Yes | No | 42,410 |
| **Subtotal** | | | | **$86,403** | **$42,410** | | | | **$42,410** |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2050 | BONNEVILLE | 2000 | 2050 | 24,446 | 0 | 6.13% | No | No | 0 |
| FY 2050 | COLUMBIA RIVER FISH MITIGATION | 2000 | 2050 | 47,006 | -0 | 6.13% | No | No | -0 |
| FY 2050 | HILLS CREEK | 2000 | 2050 | 2,630 | 0 | 6.13% | No | No | 0 |
| FY 2050 | ICE HARBOR | 2000 | 2050 | 548 | 0 | 6.13% | No | No | 0 |
| FY 2050 | JOHN DAY | 2000 | 2050 | 2,761 | 0 | 6.13% | No | No | 0 |
| FY 2050 | LOOKOUT POINT-DEXTER | 2000 | 2050 | 5,098 | 0 | 6.13% | No | No | 0 |
| FY 2050 | THE DALLES | 2000 | 2050 | 2,588 | 0 | 6.13% | No | No | 0 |
| FY 2050 | ALBENI FALLS | 2050 | 2095 | 38,323 | 38,323 | 6.73% | Yes | No | 38,323 |
| **Subtotal** | | | | **$123,401** | **$38,323** | | | | **$38,323** |
| | | | | | | | | | |
| FY 2051 | CHIEF JOSEPH | 2001 | 2051 | 345 | 0 | 5.88% | No | No | 0 |
| FY 2051 | BONNEVILLE | 2001 | 2051 | 2,530 | 0 | 5.88% | No | No | 0 |
| FY 2051 | COLUMBIA BASIN | 2001 | 2051 | 69,226 | -0 | 5.88% | No | No | -0 |
| FY 2051 | GREEN PETER-FOSTER | 2001 | 2051 | 200 | 0 | 5.88% | No | No | 0 |
| FY 2051 | DETROIT-BIG CLIFF | 2001 | 2051 | 282 | 0 | 5.88% | No | No | 0 |
| FY 2051 | COLUMBIA RIVER FISH MITIGATION | 2001 | 2051 | 6,168 | -0 | 5.88% | No | No | -0 |
| FY 2051 | HILLS CREEK | 2001 | 2051 | 8 | -0 | 5.88% | No | No | -0 |
| FY 2051 | HUNGRY HORSE | 2001 | 2051 | 552 | 0 | 5.88% | No | No | 0 |
| FY 2051 | ICE HARBOR | 2001 | 2051 | 764 | 0 | 5.88% | No | No | 0 |
| FY 2051 | JOHN DAY | 2001 | 2051 | 619 | -0 | 5.88% | No | No | -0 |
| FY 2051 | LIBBY | 2001 | 2051 | 5,562 | -0 | 5.88% | No | No | -0 |
| FY 2051 | LITTLE GOOSE | 2001 | 2051 | 4,608 | 0 | 5.88% | No | No | 0 |
| FY 2051 | LOST CREEK | 2001 | 2051 | 154 | 0 | 5.88% | No | No | 0 |
| FY 2051 | LOWER GRANITE | 2001 | 2051 | 2,025 | -0 | 5.88% | No | No | -0 |
| FY 2051 | LOWER MONUMENTAL | 2001 | 2051 | 3,301 | 0 | 5.88% | No | No | 0 |
| FY 2051 | MCNARY | 2001 | 2051 | 1,046 | -0 | 5.88% | No | No | -0 |
| FY 2051 | MINIDOKA | 2001 | 2051 | 61 | -0 | 5.88% | No | No | -0 |
| FY 2051 | UNASSIGNED BOND | 2001 | 2051 | 11,145 | -0 | 5.88% | No | No | -0 |
| FY 2051 | YAKIMA-ROZA | 2001 | 2051 | 15 | -0 | 5.88% | No | No | -0 |
| FY 2051 | ALBENI FALLS | 2051 | 2096 | 34,720 | 34,720 | 6.73% | Yes | No | 34,720 |
| **Subtotal** | | | | **$143,331** | **$34,720** | | | | **$34,720** |
| | | | | | | | | | |
| FY 2052 | CHIEF JOSEPH | 2002 | 2052 | 2 | -0 | 5.50% | No | No | -0 |
| FY 2052 | BONNEVILLE | 2002 | 2052 | 448 | -0 | 5.50% | No | No | -0 |
| FY 2052 | DETROIT-BIG CLIFF | 2002 | 2052 | 18 | 0 | 5.50% | No | No | 0 |
| FY 2052 | DWORSHAK | 2002 | 2052 | 199 | 0 | 5.50% | No | No | 0 |
| FY 2052 | HILLS CREEK | 2002 | 2052 | 2 | 0 | 5.50% | No | No | 0 |
| FY 2052 | ICE HARBOR | 2002 | 2052 | 1,014 | -0 | 5.50% | No | No | -0 |
| FY 2052 | LITTLE GOOSE | 2002 | 2052 | 27 | 0 | 5.50% | No | No | 0 |
| FY 2052 | LOWER GRANITE | 2002 | 2052 | 1,275 | -0 | 5.50% | No | No | -0 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2052 | LOWER MONUMENTAL | 2002 | 2052 | 29 | 0 | 5.50% | No | No | 0 |
| FY 2052 | THE DALLES | 2002 | 2052 | 1,226 | -0 | 5.50% | No | No | -0 |
| FY 2052 | ALBENI FALLS | 2052 | 2097 | 31,531 | 31,531 | 6.73% | Yes | No | 31,531 |
| **Subtotal** | | | | **$35,770** | **$31,531** | | | | **$31,531** |
| FY 2053 | MCNARY | 2003 | 2053 | 97 | -0 | 5.75% | No | No | -0 |
| FY 2053 | BONNEVILLE | 2003 | 2053 | 4,581 | 0 | 5.13% | No | No | 0 |
| FY 2053 | DETROIT-BIG CLIFF | 2003 | 2053 | 223 | 0 | 5.13% | No | No | 0 |
| FY 2053 | DWORSHAK | 2003 | 2053 | 761 | -0 | 5.13% | No | No | -0 |
| FY 2053 | COLUMBIA RIVER FISH MITIGATION | 2003 | 2053 | 68,440 | -0 | 5.13% | No | No | -0 |
| FY 2053 | ICE HARBOR | 2003 | 2053 | 50 | 0 | 5.13% | No | No | 0 |
| FY 2053 | LITTLE GOOSE | 2003 | 2053 | 146 | -0 | 5.13% | No | No | -0 |
| FY 2053 | LOOKOUT POINT-DEXTER | 2003 | 2053 | 135 | 0 | 5.13% | No | No | 0 |
| FY 2053 | LOWER MONUMENTAL | 2003 | 2053 | 22 | 0 | 5.13% | No | No | 0 |
| FY 2053 | LOWER SNAKE F AND W | 2003 | 2053 | 98 | -0 | 5.13% | No | No | -0 |
| FY 2053 | ALBENI FALLS | 2053 | 2098 | 49,378 | 49,378 | 6.73% | Yes | No | 49,378 |
| **Subtotal** | | | | **$123,930** | **$49,378** | | | | **$49,378** |
| FY 2054 | BONNEVILLE | 2004 | 2054 | 26,741 | 0 | 5.38% | No | No | 0 |
| FY 2054 | COUGAR | 2004 | 2054 | 15,748 | -0 | 5.38% | No | No | -0 |
| FY 2054 | COLUMBIA RIVER FISH MITIGATION | 2004 | 2054 | 60,581 | -0 | 5.38% | No | No | -0 |
| FY 2054 | LITTLE GOOSE | 2004 | 2054 | 67 | -0 | 5.38% | No | No | -0 |
| FY 2054 | LOWER MONUMENTAL | 2004 | 2054 | 3,423 | 0 | 5.38% | No | No | 0 |
| FY 2054 | LOWER SNAKE F AND W | 2004 | 2054 | 230 | 0 | 5.38% | No | No | 0 |
| FY 2054 | MCNARY | 2004 | 2054 | 6,138 | -0 | 5.38% | No | No | -0 |
| FY 2054 | THE DALLES | 2004 | 2054 | 182 | 0 | 5.38% | No | No | 0 |
| FY 2054 | ALBENI FALLS | 2054 | 2099 | 50,040 | 50,040 | 6.73% | Yes | No | 50,040 |
| **Subtotal** | | | | **$163,150** | **$50,040** | | | | **$50,040** |
| FY 2055 | BOISE | 2005 | 2055 | 903 | -0 | 5.13% | No | No | -0 |
| FY 2055 | BONNEVILLE | 2005 | 2055 | 19,725 | -0 | 5.13% | No | No | -0 |
| FY 2055 | COUGAR | 2005 | 2055 | 35,317 | -0 | 5.13% | No | No | -0 |
| FY 2055 | DETROIT-BIG CLIFF | 2005 | 2055 | 1,031 | -0 | 5.13% | No | No | -0 |
| FY 2055 | DWORSHAK | 2005 | 2055 | 713 | -0 | 5.13% | No | No | -0 |
| FY 2055 | COLUMBIA RIVER FISH MITIGATION | 2005 | 2055 | 52,039 | -0 | 5.13% | No | No | -0 |
| FY 2055 | HILLS CREEK | 2005 | 2055 | 46 | -0 | 5.13% | No | No | -0 |
| FY 2055 | HUNGRY HORSE | 2005 | 2055 | 2,951 | 0 | 5.13% | No | No | 0 |
| FY 2055 | JOHN DAY | 2005 | 2055 | 2,827 | -0 | 5.13% | No | No | -0 |
| FY 2055 | LOOKOUT POINT-DEXTER | 2005 | 2055 | 7,355 | -0 | 5.13% | No | No | -0 |
| FY 2055 | LOWER SNAKE F AND W | 2005 | 2055 | 4 | -0 | 5.13% | No | No | -0 |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2055 | MCNARY | 2005 | 2055 | 550 | 0 | 5.13% | No | No | 0 |
| FY 2055 | ALBENI FALLS | 2005 | 2055 | 481 | -0 | 5.13% | No | No | -0 |
| FY 2055 | YAKIMA-CHANDLER | 2005 | 2055 | 833 | -0 | 5.13% | No | No | -0 |
| FY 2055 | THE DALLES | 2005 | 2055 | 36,019 | 0 | 5.13% | No | No | 0 |
| FY 2055 | ALBENI FALLS | 2055 | 2100 | 50,738 | 50,738 | 6.73% | Yes | No | 50,738 |
| **Subtotal** | | | | **$211,533** | **$50,738** | | | | **$50,738** |
| FY 2056 | BOISE | 2006 | 2056 | 15 | -0 | 4.50% | No | No | -0 |
| FY 2056 | BONNEVILLE | 2006 | 2056 | 4,203 | 0 | 4.50% | No | No | 0 |
| FY 2056 | COLUMBIA BASIN | 2006 | 2056 | 3,143 | -0 | 4.50% | No | No | -0 |
| FY 2056 | COLUMBIA RIVER FISH MITIGATION | 2006 | 2056 | 360,165 | -0 | 4.50% | No | No | -0 |
| FY 2056 | LOWER MONUMENTAL | 2006 | 2056 | 285 | -0 | 4.50% | No | No | -0 |
| FY 2056 | LOWER SNAKE F AND W | 2006 | 2056 | 379 | 0 | 4.50% | No | No | 0 |
| FY 2056 | MCNARY | 2006 | 2056 | 8,169 | -0 | 4.50% | No | No | -0 |
| FY 2056 | THE DALLES | 2006 | 2056 | 2,597 | -0 | 4.50% | No | No | -0 |
| FY 2056 | ALBENI FALLS | 2056 | 2101 | 51,470 | 51,470 | 6.73% | Yes | No | 51,470 |
| **Subtotal** | | | | **$430,425** | **$51,470** | | | | **$51,470** |
| FY 2057 | BOISE | 2007 | 2057 | 76 | 0 | 5.00% | No | No | 0 |
| FY 2057 | BONNEVILLE | 2007 | 2057 | 433 | -0 | 5.00% | No | No | -0 |
| FY 2057 | COUGAR | 2007 | 2057 | 521 | 0 | 5.00% | No | No | 0 |
| FY 2057 | COLUMBIA BASIN | 2007 | 2057 | 929 | -0 | 5.00% | No | No | -0 |
| FY 2057 | COLUMBIA RIVER FISH MITIGATION | 2007 | 2057 | 49,410 | 0 | 5.00% | No | No | 0 |
| FY 2057 | HUNGRY HORSE | 2007 | 2057 | 294 | 0 | 5.00% | No | No | 0 |
| FY 2057 | JOHN DAY | 2007 | 2057 | 205 | -0 | 5.00% | No | No | -0 |
| FY 2057 | LOOKOUT POINT-DEXTER | 2007 | 2057 | 572 | 0 | 5.00% | No | No | 0 |
| FY 2057 | MCNARY | 2007 | 2057 | 33 | 0 | 5.00% | No | No | 0 |
| FY 2057 | MINIDOKA | 2007 | 2057 | 17 | 0 | 5.00% | No | No | 0 |
| FY 2057 | THE DALLES | 2007 | 2057 | 140 | -0 | 5.00% | No | No | -0 |
| FY 2057 | ALBENI FALLS | 2057 | 2102 | 52,185 | 52,185 | 6.73% | Yes | No | 52,185 |
| **Subtotal** | | | | **$104,814** | **$52,185** | | | | **$52,185** |
| FY 2058 | ALBENI FALLS | 2058 | 2103 | 52,933 | 52,933 | 6.73% | Yes | No | 52,933 |
| **Subtotal** | | | | **$52,933** | **$52,933** | | | | **$52,933** |
| FY 2059 | ALBENI FALLS | 2059 | 2104 | 53,715 | 53,715 | 6.73% | Yes | No | 53,715 |
| **Subtotal** | | | | **$53,715** | **$53,715** | | | | **$53,715** |
| FY 2060 | ALBENI FALLS | 2060 | 2105 | 54,527 | 54,527 | 6.73% | Yes | No | 54,527 |
| **Subtotal** | | | | **$54,527** | **$54,527** | | | | **$54,527** |

Table 14: Application of Amortization FY 2009 ($000s)

| Date | Project | In Service | Due | Original Balance | Amount Available | Rate | Replacement? | Rollover? | Amount Amortized |
|---|---|---|---|---|---|---|---|---|---|
| FY 2061 | ALBENI FALLS | 2061 | 2106 | 55,370 | 55,370 | 6.73% | Yes | No | 55,370 |
| **Subtotal** | | | | **$55,370** | **$55,370** | | | | **$55,370** |
| FY 2062 | ALBENI FALLS | 2062 | 2107 | 56,241 | 56,241 | 6.73% | Yes | No | 56,241 |
| **Subtotal** | | | | **$56,241** | **$56,241** | | | | **$56,241** |
| FY 2063 | ALBENI FALLS | 2063 | 2108 | 57,142 | 57,142 | 6.73% | Yes | No | 57,142 |
| **Subtotal** | | | | **$57,142** | **$57,142** | | | | **$57,142** |
| **Grand Total** | | | | **$12,644,981** | **$10,884,141** | | | | **$9,957,373** |

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# ERRATA

**Errata to**
**WP-07 Supplemental Power Rate Case**
**FY 2009 Revenue Requirement Study**
**WP-07-FS-BPA-10**

Page iii,

Delete “2 Composition of FY 2007-2009 Generation Expenses”.