DOE/CF-019
Volume 6

Department of Energy

FY 2008 Congressional Budget Request

Power Marketing Administrations

Southeastern Power Administration
Southwestern Power Administration
Western Power Administration
Bonneville Power Administration

February 2007

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Office of Chief Financial Officer

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The Department of Energy's Congressional Budget justification is available on the Office of Chief Financial Officer/CFO homepage at http://www.cfo.doe.gov/budget.

Department of Energy
Appropriation Account Summary
(dollars in thousands - OMB Scoring)

	FY 2006 Current Approp.	FY 2007 Cong. Request	FY 2007 CR Rate	FY 2008 Cong. Request	FY 2008 Request vs. FY 2007 Request $	FY 2008 Request vs. FY 2007 Request %
Discretionary Summary By Appropriation						
Energy And Water Development, And Related Agencies						
Appropriation Summary:						
Energy Programs						
Energy supply and Conservation	1,812,397	1,923,361	1,817,487	2,187,943	+264,582	+13.8%
Fossil energy programs						
Clean coal technology	-20,000	——	-5,000	-58,000	-58,000	N/A
Fossil energy research and development	580,669	469,686	558,204	566,801	+97,115	+20.7%
Naval petroleum and oil shale reserves	21,285	18,810	18,275	17,301	-1,509	-8.0%
Elk Hills school lands fund	83,520	——	2,000	——	——	——
Strategic petroleum reserve	207,340	155,430	155,430	331,609	+176,179	+113.3%
Northeast home heating oil reserve	——	4,950	4,950	5,325	+375	+7.6%
Strategic petroleum account	-43,000	——	——	——	——	——
Total, Fossil energy programs	829,814	648,876	733,859	863,036	+214,160	+33.0%
Uranium enrichment D&D fund	556,606	579,368	556,525	573,509	-5,859	-1.0%
Energy information administration	85,314	89,769	85,185	105,095	+15,326	+17.1%
Non-Defense environmental cleanup	349,687	310,358	309,946	180,937	-129,421	-41.7%
Uranium Sales and Remediation	——	——	——	——	——	——
Science	3,632,044	4,101,710	3,605,000	4,397,876	+296,166	+7.2%
Nuclear waste disposal	148,500	156,420	141,511	202,454	+46,034	+29.4%
Departmental administration	120,595	128,825	102,582	148,548	+19,723	+15.3%
Inspector general	41,580	45,507	41,784	47,732	+2,225	+4.9%
Innovative Technology Loan Guarantee Program	——	——	——	8,390	+8,390	N/A
Total, Energy Programs	7,576,537	7,984,194	7,393,879	8,715,520	+731,326	+9.2%
Atomic Energy Defense Activities						
National nuclear security administration:						
Weapons activities	6,355,297	6,407,889	6,412,001	6,511,312	+103,423	+1.6%
Defense nuclear nonproliferation	1,619,179	1,726,213	1,620,901	1,672,646	-53,567	-3.1%
Naval reactors	781,605	795,133	780,343	808,219	+13,086	+1.6%
Office of the administrator	354,223	386,576	341,991	394,656	+8,080	+2.1%
Total, National nuclear security administration	9,110,304	9,315,811	9,155,236	9,386,833	+71,022	+0.8%
Environmental and other defense activities:						
Defense environmental cleanup	6,129,729	5,390,312	5,551,812	5,363,905	-26,407	-0.5%
Other defense activities	635,578	717,788	638,129	763,974	+46,186	+6.4%
Defense nuclear waste disposal	346,500	388,080	346,163	292,046	-96,034	-24.7%
Total, Environmental & other defense activities	7,111,807	6,496,180	6,536,104	6,419,925	-76,255	-1.2%
Cerro grande fire activities	742	——	——	——	——	——
Total, Atomic Energy Defense Activities	16,222,853	15,811,991	15,691,340	15,806,758	-5,233	-0.0%
Power marketing administrations:						
Southeastern power administration	5,544	5,723	5,544	6,463	+740	+12.9%
Southwestern power administration	29,864	31,539	29,864	30,442	-1,097	-3.5%
Western area power administration	231,652	212,213	212,213	201,030	-11,183	-5.3%
Falcon & Amistad operating & maintenance fund	2,665	2,500	2,500	2,500	——	——
Colorado River Basins	——	-23,000	——	-23,000	——	——
Total, Power marketing administrations	269,725	228,975	250,121	217,435	-11,540	-5.0%
Federal energy regulatory commission	——	——	——	——	——	——
Subtotal, Energy And Water Development and Related Agencies	24,069,115	24,025,160	23,335,340	24,739,713	+714,553	+3.0%
Uranium enrichment D&D fund discretionary payments	-446,490	-452,000	——	-463,000	-11,000	-2.4%
Excess fees and recoveries, FERC	-50,015	-19,221	——	-17,462	+1,759	+9.2%
Total, Discretionary Funding	**23,572,610**	**23,553,939**	**23,335,340**	**24,259,251**	**+705,312**	**+3.0%**

Strategic Performance Overview

The Overviews in these budget requests will describe, Mission, Benefits, Strategic Themes, and Funding by Strategic Goal. These items together put the appropriation in perspective. The Annual Performance Results and Targets, Means and Strategies, and Validation and Verification sections address how the goals will be achieved and how performance will be measured. Finally, the Overviews will address R&D Investment Criteria, and Program Assessment Rating Tool (PART).

Strategic Context

Following publication of the Administration's National Energy Policy, the Department developed a Strategic Plan that defines its mission, five strategic themes for accomplishing that mission, and 16 strategic goals to support the strategic goals. Each appropriation has developed quantifiable goals to support the strategic goals. Thus, the "performance cascade" is the following:

Department Mission → Strategic Theme → Strategic Goal → GPRA Unit Program Goal (GPRA Unit) → Annual Targets → Milestones

The performance cascade accomplishes two things. First, it ties major activities for each program to successive goals and, ultimately, to DOE's mission. This helps ensure the Department focuses its resources on fulfilling its mission. Second, the cascade allows DOE to track progress against quantifiable goals and to tie resources to each goal at any level in the cascade. Thus, the cascade facilitates the integration of budget and performance information in support of the GPRA and the President's Management Agenda (PMA).

To provide a concrete link between budget, performance, and reporting, the Department developed a "GPRA[1] unit"concept. Within DOE, a GPRA Unit defines a major activity or group of activities that support the core mission and aligns resources with specific goals. Each GPRA Unit has completed or will complete a Program Assessment Rating Tool (PART). A unique program goal was developed for each GPRA unit. A numbering scheme has been established for tracking performance and reporting.[2]

R&D Investment Criteria

Another important component of our strategic planning – and the President's Management Agenda – is use of the Administration's R&D investment criteria to plan and assess programs and projects. The criteria were developed in 2001 and further refined with input from agencies, Congressional staff, the National Academy of Sciences, and numerous private sector and nonprofit stakeholders.

The chief elements of the R&D investment criteria are quality, relevance, and performance. Programs must demonstrate fulfillment of these elements. For example, to demonstrate relevance, programs are expected to have complete plans with clear goals and priorities. To demonstrate quality, programs are expected to commission periodic independent expert reviews. There are several other requirements, many of which R&D programs have and continue to undertake.

An additional set of criteria were established for R&D programs developing technologies that address industry issues. Some key elements of the criteria include: the ability of the programs to articulate the

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[1] Government Performance and Results Act of 1993

[2] The numbering scheme uses the following numbering convention: x.x.xx.xx. The first position identifies the Strategic Theme (01 through 05); the second position identifies the Strategic Goal; the third position identifies the GPRA Unit Program; the fourth position is reserved for future use.

appropriateness and need for Federal assistance; relevance to the industry and the marketplace; identification of a transition point to industry commercialization (or of an off-ramp if progress does not meet expectations), and; the potential public benefits, compared to alternative investments, that may accrue if the technology is successfully deployed.

OMB-OSTP on-going guidance describes the R&D investment criteria fully and identifies steps agencies should take to fulfill them. Where appropriate throughout these justification materials, especially in the Explanation of Funding Changes subheadings, specific R&D investment criteria and requirements are cited to explain the Department's allocation of resources.

Southeastern Power Administration

Southeastern Power Administration

Southeastern Power Administration

Proposed Appropriation Language

For necessary expenses of operation and maintenance of power transmission facilities and of marketing electric power and energy, including transmission wheeling and ancillary services, pursuant to section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), as applied to the southeastern power area, $6,463,000 to remain available until expended: Provided, that notwithstanding the provisions of 31 U.S.C. 3302, beginning in fiscal year 2008 and thereafter, such funds as are received by the Southeastern Power Administration from any State, municipality, corporation, association, firm, district, or individual as advance payment for work that is associated with Southeastern's Operation and Maintenance, consistent with that authorized in section 5 of the Flood Control Act of 1944, shall be credited to this account and be available until expended. Provided further, That, notwithstanding 31 U.S.C. 3302, up to $48,413,000 collected by the Southeastern Power Administration pursuant to the Flood Control Act of 1944 to recover purchase power and wheeling expenses shall be credited to this account as offsetting collections, to remain available until expended for the sole purpose of making purchase power and wheeling expenditures.

Southeastern Power Administration

Overview

Appropriation Summary by Program

(dollars in thousands)

	FY 2006 Current Appropriation	FY 2007 Request	FY 2007 CR	FY 2008 Request
Southeastern Power Administration				
Program Direction (PD)	5,544[a]	5,723	5,544[a]	6,463
Purchase Power and Wheeling (PPW)	47,198	48,003	47,198	62,215
Subtotal, Southeastern Program Level	52,742	53,726	52,742	68,678
Use of offsetting collections PD	0	0	0	0
Use of offsetting collections PPW	-32,713	-34,392	-32,713	-48,413
Use of alternative financing PPW	-14,485	-13,611	-14,485	-13,802
Total, Southeastern Power Administration	5,544	5,723	5,544	6,463

Preface

As the Nation moves forward to strengthen its national and economic security, the Department of Energy (DOE) leads a critical effort promoting a diverse supply and delivery of reliable, affordable, and environmentally sound energy. Southeastern Power Administration (Southeastern or SEPA) supports this effort by marketing and delivering hydroelectric power in the southeast. Southeastern's FY 2008 budget supports DOE's Strategic Theme 1, Energy Security by implementing Goal 1.3, Energy Infrastructure. Southeastern implements Goal 1.3 by promoting energy efficiency improvements among its customers and scheduling power deliveries in compliance with standards established by the Federal Energy Regulatory Commission's (FERC) Electric Reliability Organization (ERO).

Within the Southeastern appropriation, there is one program: Operation and Maintenance, which includes two subprograms: Program Direction and Purchase Power and Wheeling (PPW). Program Direction supports day-to-day agency operation and Purchase Power and Wheeling supports acquisition of contractually required transmission services and power purchases.

[a] Includes a 1% rescission of $56,000 in accordance with P.L. 109-148, Emergency Supplemental Appropriations to Address Hurricanes in the Gulf of Mexico and Pandemic Influenza, 2006.

Mission

The mission of Southeastern is to market and deliver Federal hydroelectric power at the lowest possible cost consistent with sound business practices to public bodies and cooperative utilities in the southeastern United States in a professional, innovative, customer-oriented manner, while continuing to meet the challenges of an ever-changing electric utility environment through continuous improvements.

Benefits

Southeastern supports the Department's Energy Infrastructure Goal by promoting energy efficiency and managing the dispatch and distribution of Federal hydroelectric power resources in the southeastern United States in a safe, affordable, and environmentally sound manner, while meeting national utility performance standards and balancing the diverse interests of other water resource users. This budget submission ensures effective management of Federal hydroelectric power resources and provides for: a diverse supply of generating resources that enhance regional power system reliability; power revenues that repay taxpayers' investment in the Federal power system; and regional economic benefits from delivery of Federal power to rural electric cooperatives, municipal utilities and other public entities. Southeastern has implemented rates that repay emergency power purchases within the fiscal year that they are incurred and is on track to repay the Federal investment in hydroelectric resources within required time periods.

Strategic Themes and Goals and GPRA Unit Program Goals

The Department's Strategic Plan identifies five Strategic Themes (one each for nuclear, energy, science, management, and environmental aspects of the mission) plus 16 Strategic Goals that tie to the Strategic Themes. Southeastern Power Administration supports the following goals:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3. Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U. S. infrastructure.

The programs funded within the Southeastern Power Administration appropriation have one GPRA Unit Program Goal that contributes to the Strategic Goals in the "goal cascade." This goal is Market and Deliver Federal Power.

GPRA Unit Program Goal 1.3.23.00: Market and Deliver Federal Power: Customers receive the benefits of Federal power that produce adequate revenue to repay the American taxpayers' investments allocated to power.

Contribution to Strategic Goal

Southeastern contributes to the Strategic Goal by performing its power marketing mission through two subprogram activities: Program Direction and Purchase Power and Wheeling.

Southeastern contributes to Strategic Goal 1.3, Energy Infrastructure by: marketing and delivering all available hydroelectric power from U.S. Army Corps of Engineers (Corps) dams, while balancing power needs with the diverse interests of other water resource users. Federal power is marketed and delivered in a cost-efficient manner while still working with these stakeholders to enhance the reliability of the power system and maximize the use of Federal assets to repay the investment (principal and interest), while supporting the President's Management Agenda.

Funding by Strategic and GPRA Unit Program Goal

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Strategic Goal 1.3, Energy Infrastructure GPRA Unit Program Goal 1.3.23.00, Market and Deliver Federal Power	52,742	53,726	68,678
Use of offsetting collections PD	0	0	0
Use of offsetting collections PPW	-32,713	-34,392	-48,413
Use of alternative financing PPW	-14,485	-13,611	-13,802
Total, Strategic Goal 1.3, Southeastern Power Administration	5,544	5,723	6,463

Annual Performance Results and Targets[a]

FY 2003 Results	FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets
Strategic Goal 1.3, Energy Infrastructure					
GPRA Unit Program Goal 1.3.23.00: Southeastern Power Administration, Operation and Maintenance					
Attained an average monthly NERC compliance ratings of 100 or higher for Control Performance Standard (CPS) 1 and a rating of 90 or above for CPS2. Goal Met. (ER9-2) CPS1:182 CPS 2: 97	Attained an average monthly NERC compliance ratings of 100 or higher for Control Performance Standard (CPS) 1 and a rating of 90 or above for CPS2. Goal Met. (ER9-2) CPS1:174 CPS 2: 99	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. Goal Met (ER4-51) CPS1:208 CPS 2: 100	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. Goal Met (ER4-51) CPS1:201 CPS 2: 100	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. (GG 1.4.23) CPS1: CPS 2:	Meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. (GG 1.4.23) CPS1: CPS 2:
Meet planned annual repayment of principal on Federal power investment. Goal met (ER9-2) Actual: $40 million	Meet planned annual repayment of principal on Federal power investment. Goal met (ER9-1) Actual: $45 million	Repay 1 % of the Federal investment each year. Goal Met: (ER4-51) Actual: 3.6%	Repay 1 % of the Federal investment each year. Performance Data is not available until the audit is completed. Due to draught conditions, it is doubtful that repayment will meet target.	Assure Annual Required Repayment of the Federal Investment. FY 07 required repayment is $1.0 million.	Assure Annual Required Repayment of the Federal Investment. FY 08 required repayment is $29.1 million.

[a] Annual effectiveness and efficiency performance targets will not be reported in the Department's annual Performance and Accountability Report (PAR)

Annual Performance Results and Targets, continued

FY 2003 Results	FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets
	Meet required repayment of Federal power investment within the required repayment period. Goal met. (ER9-2) Actual: $15.6 million	Provide reliable service to customers each year by maintaining full compliance with NERC and Southeastern Electric Reliability Council (SERC) operating policies and standards as a foundation for its operations reliability program. Goal Met. (ER4-51) Actual: No outstanding compliance issues.	Provide $635 million in economic benefits to the region from the sale of hydroelectric power. Goal not met. Actual benefits were $453 million	Economic benefits were discontinued from reporting beginning in FY 08.	
Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3, or the latest published Bureau of Labor Statistics' industry rate, whichever is lower. Goal met. (ER9-2) Actual: Zero Accidents	Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3, or the latest published Bureau of Labor Statistics' industry rate, whichever is lower. Goal met. (ER9-2) Actual: Zero Accidents	Recordable accident frequency rate is no longer reported as a component of strategic goal 1.4 – Energy Productivity; however, it is still tracked internally.			

Major Program Shifts and Changes

- Southeastern has implemented rates that recover emergency power purchases costs for the majority of its hydroelectric systems within the fiscal year that costs are incurred. The 2008 Budget includes an initiative for all Southeastern hydroelectric systems to adopt a one-year cost recovery policy for emergency expenses. Beginning in 2008 through 2009, all emergency expenditures Southeastern incurs out of its Continuing Fund for purchase power and wheeling activities will be recovered from ratepayers within one year. This change will assure the Treasury is repaid in a timely manner with minimal deficit impact.

- The budget provides that the interest rate for future obligations owed to the Treasury by Southeastern for power-related investments be set at the rate Governmental corporations borrow in the market, similar to interest rates current law sets for Bonneville Power Administration's borrowing from the Treasury. This new policy will be applied to all power-related investments occurring after September 30, 2006, whose interest rates are not specified in law.

- The budget does not assume reclassification of receipts from mandatory to discretionary (net zero appropriations) for the annual operating expenses of the Power Marketing Administrations because there was no agreement between the Administration and Congress to reclassify such receipts without legislative action. Nevertheless, the Administration supports this reclassification and will continue to pursue this financing arrangement.

Means and Strategies

Southeastern will use various means and strategies to achieve its GPRA Unit Program goals. However, various external factors may impact the ability to achieve these goals. The program also performs collaborative activities to help meet its goals.

The Department will implement the following means:

- Operate the Federal power system effectively and efficiently by providing training and certification to update workforce skills and updating power system operation technologies to maintain required industry standard compliance.
- Assure power rates are adequate to repay the Federal investment by conducting annual power repayment studies.
- Conduct business process reviews to maximize efficiency and eliminate redundancy.
- Provide economic benefits to the region by marketing and delivering all available hydropower.

The Department will implement the following strategies:

- Market and deliver power using appropriations, net billing, bill crediting, and offsetting collections.
- Maintain a diverse and knowledgeable workforce by providing employee training, leadership development, retention programs, and recruitment activities.
- Market all available hydropower by working with the U. S. Army Corps of Engineers (Corps), other Federal entities, States, cooperative and municipal utilities to meet the expectations of our customers while balancing the interest of other water users.
- Maintain the security of the Federal power system, facilities, and information technology (IT) systems.

- Address industry restructuring changes when needed by reclassifying positions as opportunities arise.
- Maximize the capabilities of business systems to improve processes and provide greater efficiency.

These strategies will result in a well-maintained Federal power system that is in compliance with Energy Reliability Organization operating regulations and an expert workforce to operate the system in the most effective and cost-efficient manner possible.

The following external factors could affect Southeastern's ability to achieve its program goals:

- Achieving and maintaining system reliability can be affected by weather, natural disasters, changes in the North American Electric Reliability Council (NERC) operating standards, new load patterns, deregulation of the electricity market, changing electric industry organizational structures, and additions to other transmission systems interconnected to the Federal system.
- Achieving repayment of the Federal power investment and providing economic growth to the region can be affected by weather, power markets, natural disasters, and other external costs and revenue factors.
- Achieving cost efficiencies and maintaining an operating cost per kilowatt-hour lower than the national average can be affected by security requirements, industry changes, equipment failure, regulatory mandates, Congressional requirements, and other unforeseen requirements.
- Statutory or administrative reallocation of water storage from hydropower to water supply.

In carrying out its mission to market and deliver hydroelectric power, Southeastern performs the following collaborative activities:

- Southeastern coordinates operational activities with NERC, other regional electric reliability councils, the Corps, customers and other stakeholders to provide the most efficient use of Federal assets.

Validation and Verification

To validate and verify program performance, Southeastern will conduct various internal and external reviews and audits as set forth in the Program Assessment Rating Tool. Southeastern’s programmatic activities are subject to continuing review by the Congress, the General Accounting Office, the Department of Energy, the Department of Energy’s Inspector General, the Federal Energy Regulatory Commission (FERC), the U.S. Environmental Protection Agency, the Office of Personnel Management, Southeastern, National and Regional Reliability Councils. Southeastern’s annual financial audit is conducted and prepared by an independent accounting firm.

Program Assessment Rating Tool (PART)

The Department implemented a tool to evaluate selected programs. PART was developed by the Office of Management and Budget (OMB) to provide a standardized way to assess the effectiveness of the Federal Government’s portfolio of programs. The structured framework of the PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome- and output- oriented goals, the successful completion of which will lead to benefits to the public, such as increased national security and energy security, and improved environmental conditions. DOE has incorporated feedback from OMB into the FY 2008

OMB Budget Request, and the Department will take the necessary steps to continue to improve performance.

During the FY 2004 budget cycle, Southeastern participated in a program assessment with OMB using the PART. The resulting scores and findings were provided to Congress with the FY 2004 budget request. In the PART review, OMB rated Southeastern "Moderately Effective." Southeastern's power marketing functions conform with requirements of the Flood Control Act of 1944 and other mandates and statutory requirements. To address several of OMB's concerns, a change in the legislation would be required. Annual Financial Audit and rate reviews by the Federal Energy Regulatory Commission verify that Southeastern is meeting its financial obligations. However, various General Accounting Office reports identified some areas that may be improved under existing authorizations. Southeastern and other Power Marketing Administrations (PMAs) have addressed most of these concerns to the satisfaction of OMB and implemented modifications to improve OMB's ratings. Southeastern continues to work with OMB to improve performance goals and targets. Associated annual targets are reflected in the "Annual Results and Targets" section of this budget request.

Southeastern Power Administration

Funding by Site by Program

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Southeastern Power Administration	38,257	40,115	54,876
Total, Southeastern Power Administration	38,257	40,115	54,876

Major Changes or Shifts by Site

Southeastern Power Administration
Program Direction

- Increased requirements associated with cyber security, personal information protection, information technology advancements, and power operations have been met by intensive training, automation, and staff reassignment. After almost 60 years of operating with minor FTE growth it has become necessary to add two FTEs. One FTE will support the increased reporting requirements associated with Information Technology and cyber security standards established by the National Institute Standards that are supported by DOE. The second FTE will support new power, operating, reliability and scheduling requirements, as directed by FERC's newly implemented Energy Reliability Organization (ERO).

Purchase Power and Wheeling

- Limitations on the reliability of the Electricity Grid were emphasized by the August 2003 Grid Blackout. The Energy Policy Act of 2005 addressed these limitations by creating the Energy Reliability Organization that has jurisdiction over Southeastern's operations with respect to compliance with Grid Reliability Standards. The new compliance regulations may impose financial penalties for instances of non-compliance.

Site Description

Southeastern Power Administration

Southeastern is one of four Power Marketing Administrations within the Department of Energy. Southeastern was created in 1950 to market power and energy produced at Corps hydroelectric power projects. Southeastern markets power at wholesale rates to 293 publicly owned utilities, 199 rural electric cooperatives, and one investor-owned utility in the 11 States of Florida, Georgia, South Carolina, North Carolina, Tennessee, Alabama, Mississippi, Virginia, West Virginia, Kentucky, and Illinois. Southeastern is located in Elberton, Georgia, and has no field offices.

Southeastern Power Administration
Funding Profile by Subprogram

(dollars in thousands)

	FY 2006 Current Appropriation	FY 2007 Request	FY 2008 Request
Southeastern Power Administration			
Program Direction	5,544	5,723	6,463
Purchase Power and Wheeling[a]	47,198	48,003	62,215
Total Southeastern Program Level	52,742	53,726	68,678
Offsetting Collections PPW	-32,713	-34,392	-48,413
Alternative Financing PPW	-14,485	-13,611	-13,802
Offsetting Collections PD	0	0	0
Total Southeastern Power Administration	5,544	5,723	6,463

Public Law 78-534, Flood Control Act of 1944
Public Law 95-91, DOE Organization Act of 1977, Section 302
Public Law 101-1-1, Title III, Continuing Fund (amended 1989)
Public Law 102-486, Energy Policy Act of 1992

Mission

Southeastern's power marketing and wheeling activities fulfill the requirements of Section 5 of the Flood Control Act of 1944 and reflect Southeastern's goals and objectives to market and deliver cost-based power in a safe and reliable manner, and repay the Federal investment with interest while providing environmental and economic benefits to the region.

Benefits

Southeastern's appropriation supports the Energy Strategic Goal of the Department's mission by providing delivery of reliable, affordable, and environmentally sound energy. Southeastern, in conjunction with the Corps, participates in this effort by managing the power delivery from multiple-purpose hydropower projects through effective marketing, and delivery of clean, safe, reliable, cost-based electric power. This Federal program provides reliable energy to the Nation, which can "cold-start" other power generation sources during energy emergencies.

Southeastern's program provides numerous benefits to the Nation. The significant benefits are:

- Operating a reliable Federal power system in the most effective, cost-efficient, and environmentally sound manner, while meeting national utility performance standards and balancing the diverse interests of other water resource users.
- Repaying taxpayers' investments in the Federal power system.
- Providing reliable delivery of power to customers.
- Providing low-cost power and increased competition in the region.
- Promoting regional economic growth.

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[a] The total requirements are financed through receipts and alternative financing methods, which include offsetting collections, offsetting receipts (net billing), and bill crediting. For additional detail on funding, refer to the Funding Schedule in the Purchase Power and Wheeling section.

Purchase Power and Wheeling

Funding Schedule by Activity

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Purchase Power and Wheeling			
Purchase Power	12,000	12,895	26,370
Wheeling	35,198	35,108	35,845
Subtotal, Purchase Power and Wheeling	47,198	48,003	62,215
Alternative Financing			
Net Billing	-14,485	-13,611	-13,802
Subtotal, Purchase Power and Wheeling	32,713	34,392	48,413
Offsetting Collections Realized	-32,713	-34,392	-48,413
Total, Purchase Power and Wheeling Budget Authority	0	0	0

Description

The mission of Purchase Power and Wheeling is to provide funding for acquisition of transmission services, ancillary services for the system, and pumping energy for the Richard B. Russell and Carters Pumped Storage units and support of the Jim Woodruff Project. Purchase power and transmission expenses are based on contracts Southeastern maintains with area transmission providers that agree to deliver specified amounts of Federal power from the hydropower projects to Federal power customers. Southeastern has access to a continuing fund for emergency power purchases.

The FY 2008 request uses customer receipts and net billing to pay for purchase power and wheeling expenses. Southeastern's Federal appropriation allows customers to fund purchase power and wheeling expenses in FY 2008 and subsequent years at no cost to the Federal Treasury. Some customers, acting independently or in partnerships, acquire replacement power and transmission services directly from suppliers. Southeastern will continue to assist its customers by arranging funding for these activities through alternative financing mechanisms, as needed.

Benefits

The Purchase Power and Wheeling subprogram supports Southeastern's mission to market and deliver reliable, cost-based hydroelectric power and related services. Power and services are marketed at rates designed to provide recovery of expenses and Federal investment, as established by law. The recovery of the Federal investment, or repayment, is a key performance goal for Southeastern. The Department of Energy's Strategic Plan reinforces the importance of domestic, renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past and future energy supply and Southeastern's role as a power resource by supplying hydroelectric power to its customers.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Purchase Power	**12,000**	**12,895**	**26,370**
▪ Pumping: Russell Project Purchase off-peak energy to pump water into the Richard B. Russell Project for on peak generation	8,000	8,000	13,500
▪ Pumping: Carters Project Purchase off-peak energy to pump water into the Carters Project for on peak generation	4,000	4,000	11,970
▪ Support Jim Woodruff Project Purchase of energy during periods of adverse water conditions including floods (loss of head) and drought	0	895	900
Wheeling	**35,198**	**35,108**	**35,845**
▪ Wheeling service charges Wheeling service charges for delivery of power over non-Federal systems	30,434	30,344	31,081
▪ Ancillary Services Payment for ancillary services	4,764	4,764	4,764
Total, Purchase Power and Wheeling	**47,198**	**48,003**	**62,215**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Purchase Power and Wheeling Greater than expected pumping energy costs are the result of increased fuel and fuel transportation expenses incurred by utilities that provide pumping energy. Transmission cost increases also added to higher PPW expenses.	+14,212
Total, Purchase Power and Wheeling	+14,212

Program Direction

Funding Profile by Category

	(dollars in thousands/whole FTEs)		
	FY 2006	FY 2007	FY 2008
Southeastern Power Administration			
Salaries and Benefits	3,993	4,119	4,599
Travel	126	147	405
Support Services	37	40	41
Other Related Expenses	1,388	1,417	1,418
Total, Program Direction	5,544	5,723	6,463
Total, Full Time Equivalents	41	42	44

Mission

Program Direction makes available the Federal staffing resources and associated funding necessary to provide overall direction and execution of Southeastern's program. Southeastern coordinates and cooperates with its partners to operate projects in a manner that enhances the value and reliability of hydropower. Priority is given to integrating environmental concerns and determinations into program actions. Emerging energy efficiency technologies are integrated with marketing strategies and programs.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Salaries and Benefits	**3,993**	**4,119**	**4,599**

Funding supports salaries and benefits for 44 Federal employees who market Federal hydropower, promote energy efficiency and renewable energy, and provide administrative support. The salary estimate is derived from the current year budgeted salaries, plus cost-of-living adjustments, promotions, within-grade increases, DOE-cascading performance awards, retirement payouts for unused leave (annual retirements of 3 FTEs are anticipated over the planning horizon), and overtime. Benefits are calculated as a percentage of prior year actual costs plus two additional FTEs to cover Information Management (IM) and power operations responsibilities. The funding provides for negotiation, preparation, execution, and administration of all contracts for the disposition of electric power, and ensures continuity of electric service to customers. Funding also covers operators who coordinate and schedule pumping energy among providers of pumping energy and the projects and account for all transactions relative to pumping operations of the Carters and Richard B. Russell Projects. Personnel perform Balancing Authority services for Hartwell, Richard B. Russell, and J. Strom Thurmond Projects, as well as Transmission Operator, Planning Authority, and Transmission Planner services for 20 other Federal projects. Southeastern coordinates power operations of projects with all parties, making determinations of capacity and energy availability weekly. Efficiency Performance is measured by two Efficiency Performance Indicators that provide Balancing Area compliance ratings. Southeastern's goals are: to meet or exceed the control performance standards 1 and 2 of the National

	FY 2006	FY 2007	FY 2008

(dollars in thousands)

Electric Reliability Council (NERC); and measure compliance with NERC Reliability Standards (as enforced by the ERO) and regional operating policies. Funding provides for billing, collection, and payment functions for approximately 300 contracts that benefit more than 500 preference customers. Southeastern executes budget, accounting, and financial management activities, prepares repayment analyses of each system to determine rates, and prepares rate presentations, as needed. Repayment performance is measured by comparing required to actual repayment of power investment. In support of the Energy Policy Act of 2005 and the Department's Strategic Goal 1.4, Southeastern actively promotes increased energy efficiency and development of renewable energy among its customers. Funding also covers continuing engineering studies, the review of project operations, and evaluation of impacts of proposed or actual changes to project operations. Funding also supports IM and Homeland Security initiatives.

Travel	**126**	**147**	**405**

The estimate provides transportation and per diem expenses incurred for participation in and development of regional transmission organizations; training expenses for power operator certification; relocation expenses for new FTEs; contract negotiations; preference customer meetings; rate forums; hearings and meetings; Congressional hearings; site visits of existing and new projects; promotion of energy efficiency and renewable energy via the Competitive Resource Strategy workshops and meetings; operations meetings with industry self-regulating groups. Self-regulating groups include: Southeastern Electric Reliability Council (SERC), Virginia Carolina Electric Reliability Group (VACAR), Florida Reliability Coordinating Council (FRCC); NERC; the ERO; hydropower task force and project rehabilitation meetings with the Corps, Customer, and SEPA Working Group (C2SWG); National Environmental Policy Act (NEPA) activities; training; Power Marketing Policy Forums; national and state customer meetings with the National Rural Electric Cooperative Association (NRECA), the American Public Power Association (APPA); Southeastern Federal Power Customers O&M Subcommittee meetings; Interagency Task Force on Finance; Technical Advisory Group meetings; FERC pre-filings and hearings; PJM RTO; and headquarters responsibilities.

Support Services	**37**	**40**	**41**

The Competitive Resource Strategies Program supports preference customer efforts to address energy efficiency issues, and promote development of renewable resources in support of the Department's Strategic Plan goal 1.4 and the President's National Energy Policy and the Energy Policy Act of 2005. Develop specification of training programs, prepare program plans, conduct training, and review and evaluate contractors.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Other Related Expenses	**1,388**	**1,417**	**1,418**

Provide administrative support for the office, rent, communications, maintenance, contract services (library services, support for DOE Power Marketing Liaison Office, independent audit of the Southeastern Federal Power Program financial statements), E-gov supplies, materials, and equipment and support for cyber and physical security initiatives associated with Homeland Security[a]. Support installation of electronic hardware and software for the operations center and provide maintenance to integrate real-time data from the control area and provide the data to other transmission operators in the Regional Transmission Organization (RTO), and NERC. This equipment supports additional NERC compliance requirements and system reliability. This system is a resource-intensive application that requires maintenance of interconnected fiber optic communication lines for the Supervisory Control and Data Acquisition (SCADA) system. Also reflects expenses associated with infrastructure support: telecommunications equipment; accounting system maintenance; building and computer security equipment; computer hardware and software; and office equipment and financial management system (Oracle). This funding allows the agency to fulfill its obligations under Strategic Theme 1, Energy Security and Goal 1.3, Energy Infrastructure.

Total, Program Direction	**5,544**	**5,723**	**6,463**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Salaries and Benefits	
▪ Fiscal Year 2008 salaries are derived from the FY 2007 budgeted salaries, plus cost-of-living adjustments, promotions, within-grade increases, DOE-cascading performance awards, retirement payouts for unused leave, 2 additional FTE for IM and Power Operations, and overtime. Benefits are calculated based on a percentage of prior year actuals, as applied against FY 2007 calculated salaries.	+480
Travel	
▪ Derived from present travel expenses and factors in increased fuel and airfare costs. Also includes expenses for relocation of 2 new FTEs, and relocation of key personnel to replace retiring directors.	+258
Support Services	
▪ Increase in funding for co-sponsored energy efficiency services and renewable energy acquisition support for municipal and cooperative utilities.	+1

[a] Southeastern is required to meet the Common Identification Standard for Federal Employees and Contractors, as required by HSPD-12, FIPS Publication 201, Personal Identification verification for Federal Employees and Contractors, NIST 800-73, Integrated Circuit Card for Personal Identity and Verification for Federal Employees and Contractors, NIST 800-76, Biometric Data Specification for Personal Identity Verification and all other DOE requirements.

	FY 2008 vs. FY 2007 ($000)
Other Related Expenses	
▪ Rent increase due to inflation	+8
▪ Audit due to new DOE requirement for special opinion letter	+3
▪ Communications expenses decreased	-2
▪ Printing and Reproduction Expenses decrease	-3
▪ Increase in tuition for operator licenses, IM, Project Management and other training	+5
▪ Maintenance expenses decreased	-4
▪ Supplies and materials expense increase is related to IT supplies	+71
▪ Contract services expenses decreased	+5
▪ Equipment expenses decreased	-83
▪ Working Capital Fund increased to reflect headquarters operating expenses	+1
Total, Other Related Expenses	+1
Total Funding Change, Program Direction	**+740**

Support Services by Category

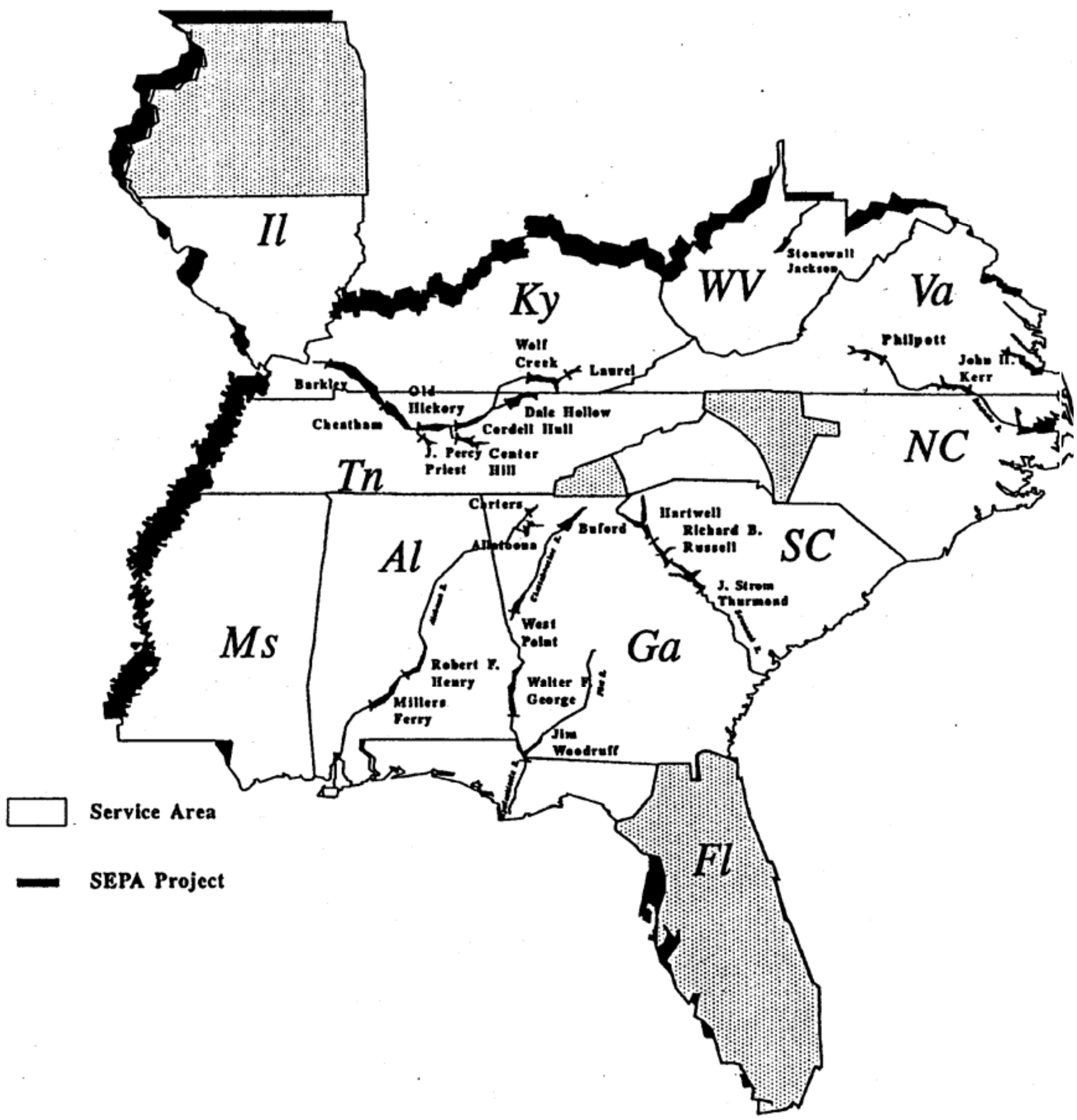
	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Management support			
Management and Professional Support Services[a]	37	40	41
Total, Management Support	37	40	41
Total, Support Services	37	40	41

[a] Co-sponsor energy efficiency services and renewable energy acquisition support for preference customers.

Other Related Expenses by Category

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Other Related Expenses			
Rent to GSA	333	340	347
Rent to Others	7	8	9
Audit of Financial Statements	150	160	163
Communications, Utilities, Misc.	272	264	262
Printing and Reproduction	6	7	4
Tuition	20	25	30
Maintenance Agreements	99	106	102
Supplies and Materials	62	58	129
Contract Services	278	236	241
Equipment	134	183	100
Working Capital Fund	27	30	31
Total, Other Related Expenses	1,388	1,417	1,418

Service Area Map



Revenue and Receipts

(in thousands)

	FY 2006	FY2007[d]	FY2008[e]	FY2009[f]	FY 2010	FY 2011	FY 2012
Southeastern Power Administration							
Gross Revenues	217,343	220,670	239,736	242,596	244,011	245,106	246,253
Agency Rate Adjustment	0	540	583	599	628	670	708
Net Billing (Credited as an Offsetting Receipt)	-14,485	-13,611	-13,802	-14,002	-14,213	-14,435	-14,667
Total Cash Receipts	202,858	207,599	226,517	229,193	230,426	231,341	232,294
Continuing Fund	-9,873	0	0	0	0	0	0
Use of Offsetting Collections to fund PPW	-32,713	-34,392	-48,413	-49,520	-50,642	-51,782	-53,007
Total Offsetting Collections	-42,586	-34,392	-48,413	-49,520	-50,642	-51,782	-53,007
Cumberland Rehabilitation	-7,000	-8,000	-8,000	-9,000	-6,000	-3,000	-9,000
GA-AL-SC Rehabilitation	-3,000	-3,000	-3,000	-3,000	-3,000	0	0
Kerr-Philpott Rehabilitation	0	0	-400	-600	-600	-600	-600
Total Proprietary Receipts	150,272	162,207	166,704	167,073	170,184	175,959	169,687
Percent of Sales to Preference Customers	99%	99%	99%	99%	99%	99%	99%
Energy Sales and Power Marketed (megawatt hours)	6,211,854	7,886,000	7,886,000	7,886,000	7,886,000	7,886,000	7,886,000

[d] Expected increase in Kerr-Philpott rates of 25% in FY 2007.
[e] Expected increase in GA-AL-SC rates of 15% in FY 2008.
[f] Expected increase in Cumberland rates of 5% in FY 2009.

System Statistics

	FY 2006 Actual	FY 2007 Estimate	FY 2008 Estimate
Generating Capacity:			
Nameplate Capacity (KW)	3,392,375	3,392,375	3,392,375
Peak Capacity (KW) [g]	3,710,000	3,710,000	3,710,000
Generating Stations			
Generating Projects (Number)	22	22	22
Available Energy			
Energy from Streamflow (MWH)	5,652,920	7,459,272	7,459,272
Energy generated from Pumping (MWH)	480,440	427,128	427,128
Energy Purchased for Replacement (MWH)	78,494	75,000	75,000
Total, Energy available for marketing [h] (MWH)	6,211,854	7,961,400	7,961,400

[g] Southeastern markets capacity based on nameplate plus an overload factor. NERC requires that Southeastern keep a portion of the capacity in reserve for emergency purposes and to cover losses.
[h] Gross amount. Transmission losses are deducted from this amount to estimate the amount of energy marketed.

Power Marketed, Wheeled, or Exchanged by Project

Project	State	Plants	Installed Capacity (KW)	FY 2006 Actual Power (GWH)	FY 2007 Estimated Power (GWH)	FY 2008 Estimated Power (GWH)
Kerr-Philpott System				271 *	463 *	463 *
John H. Kerr	VA-NC	1	204,000			
Philpott	VA	1	14,000			
Georgia-Alabama-South Carolina System				3,462 *	4,059 *	4,059 *
Allatoona	GA	1	74,000			
Buford	GA	1	86,000			
Carters	GA	1	500,000			
J. Strom Thurmond	GA-SC	1	280,000			
Walter F. George	GA-AL	1	130,000			
Hartwell	GA-SC	1	344,000			
R. F. Henry	AL	1	68,000			
Millers Ferry	AL	1	75,000			
West Point	GA-AL	1	73,375			
Richard B. Russell	GA-SC	1	600,000			
Jim Woodruff Project	FL-GA	1	30,000	215	237	237
Cumberland System				2,185 *	3,127 *	3,127 *
Barkley	KY	1	130,000			
Center Hill	TN	1	135,000			
Cheatham	TN	1	36,000			
Cordell Hull	TN	1	100,000			
Dale Hollow	TN	1	54,000			
Old Hickory	TN	1	100,000			
J. Percy Priest	TN	1	28,000			
Wolf Creek	TN	1	270,000			
Laurel	TN	1	61,000			
Stonewall Jackson Project[i]	WV	1	0	0	0	0
Total Power Marketed[j]		23	3,392,375	6,133	7,886	7,886

[i] Stonewall Jackson Project de-authorized in 2006.
[j] Does not include 78.5 GWH of power purchased for replacement.

Pending Litigation

Although Southeastern is not a party to the cases listed below, we are monitoring them in order to assess any impacts the outcomes may have on Southeastern's operations.

Southeastern Federal Power Customers, Inc., (SeFPC) Lawsuit Against the Corps: In late 2000, SeFPC sued the Corps in U.S. District Court for the District of Columbia regarding the management of water withdrawal contracts and collection of revenues from certain water users in Georgia. The parties agreed to settlement discussions aided by a Court-sanctioned mediator and on January 9, 2003, a mediated settlement was reached by SeFPC, the Corps, the State of Georgia, and various Georgia water users holding Corps water withdrawal contracts at Lake Lanier (Buford Project). The settlement has been contested by the States of Alabama, Florida, and other intervening parties as being in conflict with prior pending litigation in Alabama and efforts by the three States to negotiate water compacts for the Alabama-Coosa-Tallapoosa (ACT) and Apalachicola-Chattahoochee-Flint (ACF) River Basins in Georgia, Florida, and Alabama. Also, it is argued that implementation of the settlement would adversely affect other litigation pending in Alabama and Georgia involving these parties.

On February 10, 2004, the Court overruled the objections of the States of Alabama and Florida to the Settlement Agreement and declared it valid and approved. The Court also held that the Settlement Agreement may be executed, filed, and thereafter performed in accordance with its terms, provided the preliminary injunction entered on October 15, 2003, in the Northern District of Alabama is first vacated. The order for injunction was appealed to the 11th Circuit of Appeals and the Court, after oral arguments, returned the Alabama order to the District Court for further consideration. Briefs and oral arguments were presented in late September, and no action has been taken by the Alabama District Court. Appeals from the February order were filed in April by Florida and Alabama and are currently being briefed by the parties.

Alternative Financing

2006	Transmission	Purchase Power	Offsetting Collections	Net Billing	Appropriated Funds
Jim Woodruff System	264	0	0	-264	0
Kerr-Philpott System	4,738	0	-4,738	0	0
GA-AL-SC System	20,414	12,000	-27,780	-4,634	0
Cumberland System	9,782	0	-195	-9,587	0
	35,198	12,000	-32,713	-14,485	0
2007					
Jim Woodruff System	0	895	-695	-200	0
Kerr-Philpott System	5,130	0	-5,130	0	0
GA-AL-SC System	20,228	12,000	-28,404	-3,824	0
Cumberland System	9,750	0	-163	-9,587	0
	35,108	12,895	-34,392	-13,611	0
2008					
Jim Woodruff System	0	900	-700	-200	0
Kerr-Philpott System	4,913	0	-4,913	0	0
GA-AL-SC System	21,175	25,470	-42,630	-4,015	0
Cumberland System	9,757	0	-170	-9,587	0
	35,845	26,370	-48,413	-13,802	0

Southwestern Power Administration

Southwestern Power Administration

Southwestern Power Administration

Proposed Appropriation Language

For necessary expenses of operation and maintenance of power transmission facilities and of marketing electric power and energy, for construction and acquisition of transmission lines, substations and appurtenant facilities, and for administrative expenses, including official reception and representation expenses in an amount not to exceed $1,500 in carrying out section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), as applied to the southwestern power area, $30,442,000, to remain available until expended: Provided, That, notwithstanding 31 U.S.C. 3302, up to $35,000,000 collected by the Southwestern Power Administration pursuant to the Flood Control Act to recover purchase power and wheeling expenses shall be credited to this account as offsetting collections, to remain available until expended for the sole purpose of making purchase power and wheeling expenditures.

Southwestern Power Administration

Overview

Appropriation Summary by Program

(dollars in thousands)

	FY 2006 Current Appropriation	FY 2007 Request	FY 2007 CR	FY 2008 Request
Southwestern Power Administration [a]				
Operation and Maintenance	42,264	45,139	50,864	83,492
Subtotal, Southwestern Power Administration	42,264	45,139	50,864	83,492
Offsetting Collections	-3,000	-3,000	-3,000	-35,000
Alternative Financing	-9,400	-10,600	-18,000	-18,050
Total, Southwestern Power Administration	29,864	31,539	29,864	30,442

Preface

As the Nation moves forward to strengthen its national energy and economic security, the Department of Energy (DOE) leads this critical effort by promoting a diverse supply and delivery of reliable, affordable, and environmentally sound energy. Southwestern Power Administration (Southwestern) exists to meet its public responsibilities, consistent with the Flood Control Act of 1944, to market and reliably deliver Federal power, recover power costs, and repay the Federal investment consistent with sound business principles, giving preference to public bodies and cooperatives while encouraging the most widespread use of power, and implementing public policy.

Within the Southwestern appropriation, there is one program: Operation and Maintenance (four subprograms).

Mission

The mission of Southwestern is to market and reliably deliver Federal hydroelectric power with preference to public bodies and cooperatives. This is accomplished by maximizing the use of Federal assets to repay the Federal investment and participating with other water resource users in an effort to balance their diverse interests with power needs within broad parameters set by the U. S. Army Corps of Engineers (Corps), and implementing public policy.

[a] Southwestern's budget request for the Purchased Power and Wheeling subprogram reflects anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested. This increase will ensure adequate funding under all but the most severe hydrological conditions, at which time the Continuing Fund, presently codified at 16 U.S.C. 825x-1, as amended by Public Law No. 101-101 will be activated.

Benefits

Southwestern's appropriation supports DOE's Energy Strategic Theme 1 by enabling the delivery of reliable, affordable and environmentally sound energy, and operation of a reliable transmission system which is an integral part of the Nation's transmission grid. Southwestern, in conjunction with the Corps, participates in this effort by managing the multipurpose operation of the Federal hydropower system. This enables effective marketing, generation, and delivery of clean, reliable, cost-based electric power.

Southwestern's program provides the Nation numerous benefits, which include:

- Operating a reliable Federal power system in an effective, cost efficient, and environmentally sound manner while meeting National utility performance standards and balancing the diverse interests of other water resource users.
- Producing power at the lowest cost-based rates possible, consistent with sound business practices.
- Repaying the American taxpayers' investments in the Federal power system.
- Providing reliable delivery of power to customers.
- Providing approximately $474 million in economic benefits under average water conditions.
- Providing regional power restoration assistance to other non-hydropower generation sources during outage emergencies.
- Repaying the annual costs of operation of the Federal hydropower system with revenues from customers during the year those costs are incurred under normal operations.

Strategic Themes and Goals and GPRA Unit Program Goal

DOE's Strategic Plan identifies five Strategic Themes (one each for nuclear, energy, science, management, and environmental aspects of the mission) plus 16 Strategic Goals that tie to the Strategic Themes. The Southwestern Power Administration appropriation supports the following theme and goal:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3, Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

The program funded within the Southwestern Power Administration appropriation has one GPRA Unit Program Goal that contributes to the Strategic Goals in the "goal cascade." This goal is:

GPRA Unit Program Goal 1.3.24.00: Southwestern Power Administration: Market and Deliver Federal Power: Provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

Contribution to Strategic Goal

Southwestern contributes to the Strategic Goal through four subprograms (Program Direction, Operations and Maintenance, Construction, and Purchased Power and Wheeling) supported by appropriations, appropriations offset by receipts, Federal power receipts, and alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances). This is accomplished by marketing and delivering all available hydroelectric power from the Corps' dams while working with other water resource users to balance diverse interests with power needs within broad parameters set by the Corps; operating and maintaining a Federal power system, which is an integral part of the Nation's electrical grid, in an effective and cost efficient manner to assure reliability; and maximizing the use of Federal assets to repay the investment (principal and interest) as well as operation and maintenance costs of the Southwestern Federal power system while supporting the President's Management Agenda initiatives.

Funding by Strategic and GPRA Unit Program Goal

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Strategic Goal 1.3, Energy Productivity			
GPRA Unit Program Goal 1.3.24.00, Operation and Maintenance	42,264	44,455	83,492
Subtotal, Strategic Goal 1.3 (Southwestern Power Administration)	42,264 [a]	44,455	83,492
Offsetting Collections	-3,000	-3,000	-35,000
Alternative Financing	-9,400	-10,600	-18,050
Subtotal, Strategic Goal 1.3 (Southwestern Power Administration)	29,864	30,855	30,442
All Other			
Safeguards and Security	0	684	0
Total, All Other	0	684	0
Total, Strategic Goal 1.3 (Southwestern Power Administration)	29,864	31,539	30,442

[a] Reflects a 1% rescission in accordance with Public Law No. 109-148, Emergency Supplemental Appropriations to Address Hurricanes in the Gulf of Mexico and Pandemic Influenza 2006, in the amount of $301,660 (Program Direction, $199,580; Operations and Maintenance $70,420; Construction, $31,660).

Annual Performance Results and Targets

FY 2003 Results	FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets
Strategic Goal 1.3, Energy Infrastructure GPRA Unit Program Goal 1.3.24.00: Southwestern Power Administration, Operation and Maintenance					
Attain average NERC compliance ratings of 100 or higher for Control Performance Standard 1, and 90 or above for Control Performance Standard 2. (PMA9-2a) GREEN Actual: CPS 1: 187.3 CPS 2: 99.5	Attain average NERC compliance ratings of 100 or higher for Control Performance Standard 1, and 90 or above for Control Performance Standard 2. (ER9-3) GREEN Actual: CPS 1: 183.8 CPS 2: 99.6	Meet industry averages (CPS1: 162.0 and CPS2: 96.7) and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. GREEN Actual: CPS 1: 186.74 CPS 2: 99.40	Meet industry averages (CPS1: 161.8 and CPS2: 97.2) and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances. GREEN Actual: CPS 1: 180.23 CPS 2: 99.18	Meet industry averages (CPS1: 161.8 and CPS2: 97.2) and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances.	Meet industry averages (CPS1: 161.8 and CPS2: 97.2) and at a minimum, meet NERC Control Performance Standards (CPS) of CPS1>100 and CPS2>90. CPS1: minute by minute measures a generating system's ability to match supply to changing demand requirements and support desired system frequency (about 60 cycles per second); CPS2: measures systems ability to limit the magnitude of generation and demand imbalances.
Meet planned annual repayment of principal on Federal power investment. (PMA9-2b) GREEN Actual: $17.0 million	Meet planned annual repayment of principal on Federal power investment. (ER9-3) GREEN Actual: $29.2 million	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower. [a] GREEN Actual: Southwestern: $0.0109 National industry average: $0.0126 Therefore, Southwestern less than National industry average.	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower. GREEN Actual: Southwestern: $0.0116 National industry average: $0.0136 Therefore, Southwestern is less than National industry average.	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower.	Provide power at the lowest possible cost by keeping average operation and maintenance cost per kilowatt-hour below the National average for hydropower.

[a] National average for hydropower O&M cost per kilowatt-hour is derived from a sampling of 30 hydropower utilities' annual reports, the Federal Energy Regulatory Commission's Form 1, and the Energy Information Administration's Form 412.

FY 2003 Results	FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets
Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3, or the Bureau of Labor Statistics' industry rate (5.0), whichever is lower. (PMA9-2c) GREEN Actual: 1.3 recordable injuries per 200,000 hours worked.	Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 5.3, or the Bureau of Labor Statistics' industry rate (3.7), whichever is lower. (ER9-3) GREEN Actual: 2.6 recordable injuries per 200,000 hours worked.	Provide $457 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions). GREEN Actual: $488 million	Provide $462 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions). YELLOW Actual: $322 million	Provide $468 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions).	Provide $474 million in economic benefits to the region from the sale of hydroelectric power (under average water conditions).
	Repay the Federal investment within the required repayment period. (ER9-3) GREEN Actual: met all required repayment.	Repay the Federal investment within the required repayment period. GREEN Actual: met all required repayment.	Repay the Federal investment within the required repayment period. GREEN Actual: met all required repayment.	Repay the Federal investment within the required repayment period.	Repay the Federal investment within the required repayment period.
	System Reliability Performance: Achieve a System Average Interruption Duration Index (SAIDI) of not more than 150 minutes of total preventable outages per year. (ER9-3) GREEN Actual: < 150 minutes of total preventable outages.	Provide reliable service to customers annually under normal operations, by not allowing system voltage to fall below 95% of nominal (e.g. 161kV) for more than 30 minutes during any preventable condition. GREEN Actual: Southwestern did not incur any violations where system voltage fell below 95% if nominal for more than 30 minutes of preventable condition.	Operate the transmission system so there are no more than 3 preventable outages annually. GREEN Actual: Southwestern incurred one preventable outage.	Operate the transmission system so there are no more than 3 preventable outages annually.	Operate the transmission system so there are no more than 3 preventable outages annually.

Means and Strategies

Southwestern will use various means and strategies to achieve its GPRA Unit Program Goal; however, various external factors may impact achievement of this goal. Southwestern also collaborates with others to meet its goal.

Southwestern will implement the following means:

- Achieve and maintain financial integrity.
- Maintain power system reliability.
- Operate the Federal power system effectively and efficiently.
- Provide power at the lowest possible cost.
- Provide economic benefits to the region.

Southwestern will implement the following strategies:

- Market all available hydropower generated at the Corps multipurpose projects and work with the Corps, states, cooperatives, and municipalities to meet statutory requirements while balancing the interests of other water users.
- Assure power rates are sufficient to repay all annual operating costs and the Federal investment with interest by conducting annual power repayment studies and submitting needed rate adjustments to the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) for approval.
- Meet Southwestern's limited 1200-hour peaking power contractual obligations with necessary purchased power and wheeling through the use of Federal power receipts; alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances); and Continuing Fund Authority, as necessary in years of below average hydropower generation.
- Utilize the following funding mechanisms: appropriations, appropriations offset by receipts, use of Federal power receipts, and alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances).
- Maintain a diverse and knowledgeable workforce through employee training, skills gap analysis, leadership development, retention programs, and aggressive recruitment activities.
- Meet North American Electric Reliability Corporation (NERC) requirements by performing certification and annual emergency operations training for its power system dispatchers and others on a space available basis.
- Maintain the security of the Federal power system, facilities, and information technology (IT) systems.
- Address changes in the electric utility industry, technology, and workload by moving administrative and indirect positions to direct ("front line") positions as opportunities arise.
- Maximize the capabilities of business systems to improve processes and provide greater efficiency.

These strategies will result in a well-maintained, modern Federal power system, and an expert workforce to operate and maintain the system in the most effective and cost efficient manner possible.

The following external factors could impact Southwestern's ability to achieve its program goal:

- Southwestern's program goal could be impacted by weather, natural disasters, changes in NERC operating standards, transmission line constraints, new load patterns, deregulation of the electricity market, changing electric industry organizational structures, equipment failure, Congressional requirements, power markets, revenue factors, additions to other utilities' transmission systems interconnected with the Federal system, and other unforeseen requirements.

Successful collaboration of the Federal hydropower partners is necessary for Southwestern to achieve its program goal. Southwestern coordinates its operational activities with the Corps, customers, competing resources interests, the Southwest Power Pool Regional Transmission Organization, and Congress to provide the most efficient and effective use of Federal assets and to ensure NERC and regional reliability council standards are met.

Validation and Verification

Southwestern will routinely conduct various internal and external reviews, studies, and audits to validate and verify program performance. Southwestern's program also is subject to continuing review by internal and external entities such as Congress, the Government Accountability Office (GAO), the DOE's Inspector General, FERC, the U.S. Environmental Protection Agency, the Office of Personnel Management, the Office of Management and Budget (OMB), DOE, Southwestern, NERC, the regional electric reliability council, and Southwestern's Federal power customers.

Achievement of Southwestern's objectives is evaluated on a daily basis, in the context of mission responsibilities and the continued impacts of external factors. Each objective has performance targets that are reported quarterly to DOE. Southwestern establishes a plan of action to improve any performance below established quarterly standards. Measuring performance against these targets indicates whether Southwestern is achieving its objectives.

Program Assessment Rating Tool (PART)

DOE implemented a tool to evaluate selected programs. PART was developed by OMB to provide a standardized way to assess the effectiveness of the Federal Government's portfolio of programs. The structured framework of the PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome- and output-oriented goals, the successful completion of which will lead to benefits to the public, such as increased national security and energy security, and improved environmental conditions. DOE has incorporated feedback from OMB beginning in the FY 2006 Budget Request, and DOE will take the necessary steps to continue improving performance.

Southwestern received a "Moderately Effective" PART rating for both the FY 2004 and FY 2005 budget cycles from OMB primarily due to OMB's view that improvements were needed to Southwestern's long- and short-term goals. In February 2004, Southwestern took the lead to improve its goals by working with its OMB Examiner through a series of conference calls. An agreement was reached in which both parties were satisfied that Southwestern's new long- and short-term goals meet the PART criteria. These mutually agreed to performance goals and targets, initially reflected in the FY 2006 budget, provide a strong link to Southwestern's funding request.

Significant Policy or Program Shifts

- The budget includes an initiative to recover from ratepayers within one year any expenditure Southwestern incurs out of its Continuing Fund for purchase power and wheeling costs. This change will assure the Treasury is repaid in a timely manner with minimal deficit impact. Southwestern will begin implementing this initiative in FY 2009.
- The budget provides that the interest rate for future obligations owed to the Treasury by Southwestern for power-related investments be set at the rate Governmental corporations borrow in the market, similar to the interest rates current law sets for Bonneville Power Administration's borrowing from the Treasury. This new policy will be applied to all power-related investments occurring after September 30, 2006, whose interest rates are not specified in law.
- The budget does not assume reclassification of receipts from mandatory to discretionary (net zero appropriations) for the annual operating expenses of the Power Marketing Administrations because there was no agreement between the Administration and Congress to reclassify such receipts without legislative action. Nevertheless, the Administration supports this reclassification and will continue to pursue this financing arrangement.

Southwestern Power Administration

Funding by Site by Program

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Southwestern Power Administration	42,264	45,139	83,492
Total, Southwestern Power Administration	42,264	45,139	83,492

Site Description

An Agency of the Department of Energy, Southwestern Power Administration (Southwestern) was created in 1943 to market and deliver power and energy produced at U.S. Army Corps of Engineers (Corps) hydroelectric power projects. Southwestern markets and delivers power at wholesale rates to 78 municipal utilities, 22 rural electric cooperatives, and three government entities in the six States of Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas. In order to integrate the operation of the Federal hydroelectric generating plants and to transmit power from 24 multi-purpose Corps' dams to customers, Southwestern operates and maintains 1,380 miles of high-voltage transmission line, 24 substations, and 47 microwave and very high frequency radio sites. Southwestern operates from its Headquarters in Tulsa, Oklahoma, a Dispatch Center in Springfield, Missouri, and maintenance facilities in Jonesboro, Arkansas; Gore, Oklahoma; and Springfield, Missouri.

Operation and Maintenance

Funding Profile by Subprogram

(dollars in thousands)

	FY 2006 Current Appropriation	FY 2007 Request	FY 2008 Request
Operation and Maintenance			
Program Direction (PD)	19,758	20,782	22,214
Operations and Maintenance (O&M)	6,972	7,145	11,978
Construction (CN)	3,134	3,612	4,300
Purchased Power and Wheeling (PPW)	12,400 [a]	13,600	45,000 [b]
Subtotal, Operation and Maintenance	42,264	45,139	83,492
Offsetting Collections, PPW	-3,000	-3,000	-35,000
Alternative Financing, PD	n/a	n/a	-877
Alternative Financing, O&M	n/a	n/a	-6,304
Alternative Financing, CN	n/a	n/a	-869
Alternative Financing, PPW	-9,400	-10,600	-10,000
Total, Operation and Maintenance	29,864	31,539	30,442

Public Law Authorizations:

Public Law No. 78-534, Section 5, Flood Control Act of 1944
Public Law No. 95-91, Section 302, DOE Organization Act of 1977
Public Law No. 100-71, Supplemental Appropriations Act, 1987
Public Law No. 101-101, Title III, Continuing Fund (amended 1989)
Public Law No. 102-486, Section 721, Energy Policy Act of 1992
Public Law No. 108-137, Appropriations Act, FY 2004

[a] The Continuing Fund presently codified at 16 U.S.C. 825s-1, as amended by Public Law No. 101-101, has been and will continue to be used to defray emergency expenses to ensure continuity of electric service and continuous operation of the facilities. For additional detail on funding, refer to the Funding Schedule in the PPW section.
[b] Southwestern's PPW budget request reflects an increase in authority to use Federal power receipts for anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested.

Mission

The mission of the Operation and Maintenance program is to market and reliably deliver Federal hydroelectric power with preference to public bodies and cooperatives. This is accomplished by maximizing the use of Federal assets to repay the Federal investment and participating with other water resource users in an effort to balance their diverse interests with power needs within broad parameters set by the U.S. Army Corps of Engineers (Corps), and implementing public policy.

Benefits

Southwestern's appropriation supports DOE's Energy Strategic Theme 1 by enabling the delivery of reliable, affordable and environmentally sound energy, and operation of a reliable transmission system which is an integral part of the Nation's transmission grid. Southwestern, in conjunction with the Corps, participates in this effort by managing the multipurpose operation of the Federal hydropower system. This enables effective marketing, generation, and delivery of clean, reliable, cost-based electric power.

Southwestern's program provides the Nation numerous benefits, which include:

- Operating a reliable Federal power system in an effective, cost efficient, and environmentally sound manner while meeting National utility performance standards and balancing the diverse interests of other water resource users.
- Producing power at the lowest cost-based rates possible, consistent with sound business practices.
- Repaying the American taxpayers' investments in the Federal power system.
- Providing reliable delivery of power to customers.
- Providing approximately $474 million in economic benefits under average water conditions.
- Providing regional power restoration assistance to other non-hydropower generation sources during outage emergencies.
- Repaying the annual costs of operation of the Federal hydropower system with revenues from customers during the year those costs are incurred under normal operations.

Operations and Maintenance

Funding Schedule by Activity

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Operations and Maintenance (O&M)			
Power Marketing	436	200	1,028
Operations	2,544	2,834	4,321
Maintenance	3,992	3,811	6,204
Capitalized Movable Equipment	0	300	425
Subtotal, Operations and Maintenance	6,972 [a]	7,145	11,978
Alternative Financing	n/a	n/a	-6,304
Total, Operations and Maintenance	6,972	7,145	5,674

Description

The mission of the Operations and Maintenance subprogram is to assure continued reliability of the Federal power system by replacing aging infrastructure and removing constraints that would impede power flows, thus meeting the expectations of the 2005 Energy Policy Act (EPACT), National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects the Southwestern Power Administration's (Southwestern) program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

Benefits

The activities of the Operations and Maintenance subprogram are critical components in maintaining the reliability of the Federal power system facilities, which are part of the Nation's interconnected generation and transmission system. Through the use of renewable hydroelectric energy, Southwestern provides clean, safe, reliable, cost-based electric power to its customers while limiting environmental impacts. EPACT, NEP, and DOE's Strategic Plan reinforce the importance of renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past, current, and future energy supply and Southwestern's "important role in meeting demand" by supplying hydroelectric power to its customers. All emphasize the need to repair, maintain, and improve the transmission and generation infrastructure to avoid loss of reliability. Southwestern also has the capability to provide reliable off-site power to help restore other power generation sources during outage emergencies.

Southwestern's participation in the regional electric reliability council and the Regional Transmission Organization (RTO) in Southwestern's marketing area, consistent with EPACT, reinforces

[a] Reflects a 1% rescission in accordance with P.L. 109-148, Emergency Supplemental Appropriations to Address Hurricanes in the Gulf of Mexico and Pandemic Influenza 2006, in the amount of $70,420.

Southwestern's role as part of the Nation's interconnected electric grid. DOE identified the Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS), transmission lines, substations, and communication facilities as critical infrastructure. As the demand for the transmission of power increases on the Nation's power systems, the need to maintain, repair, and provide for improvements on the Federal power system is critical in assuring reliable delivery.

Southwestern will use appropriations for capital investments, appropriations offset by receipts for non-capital annual expenses, and will continue to use alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances) with customers and others who provide services or funds to assure a dependable and reliable Federal power system. Southwestern's authority to use net billing and bill crediting is inherent in the authority provided by the Flood Control Act of 1944, and has been affirmed by the Comptroller General.[a]

Southwestern's planned Operations and Maintenance projects are subject to change based on unanticipated equipment failure, customer needs, and weather conditions. The realities of maintaining a complex interconnected power system means unforeseen priority projects will arise periodically causing a reprioritization of planned projects. All projects share the commonality of maintaining, repairing, and improving the aging and deteriorating infrastructure to ensure the reliability of the Federal power system.

Detailed Justification

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Power Marketing	**436**	**200**	**1,028**

The Power Marketing activity funds technical and economic studies to support Southwestern's transmission planning, water resources, communications, and maintenance activities. Technical and economic studies provide data to analyze and evaluate the impacts of proposed operational changes and decision-making based on cost/benefit analyses. Funding is also required for Southwestern's participation in the RTO and to provide regional power restoration assistance to other non-hydropower generation sources during outage emergencies. The NEP identified bottlenecks in the Nation's interconnected electrical grid, which could impede power flows. Studies to identify any constraints on Southwestern's system will be conducted. These studies will show how the marketing and delivery of power is operationally impacted.

Southwestern currently has transmission assets that are within other utilities' control areas. This arrangement requires Southwestern to provide power losses to those other utilities, and increases the complexity of operating Southwestern's transmission system during both normal and emergency conditions, as well as the complexity of performing proper settlement accounting and regional tariff administration under the RTO.

The funding level for this activity is derived from Southwestern's engineering plan, negotiated architect/engineering contracts, and the number of studies required per year. The increase in funding for this activity reflects a change in Southwestern's control area boundary to reduce power losses provided, thereby saving annual costs, and enabling easier reconciliation of power billing and operations with the regional reliability council and the RTO.

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[a] Honorable Secretary of the Interior B-125, 127 (February 14, 1956) available at WL 3064 (Comp. Gen.).

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Operations	**2,544**	**2,834**	**4,321**

The Operations activity funds communication activities associated with the dispatch and delivery of power; environmental, safety and health activities; and other transmission activity costs such as physical security, cyber security, and day-to-day power dispatch functions.

▪ **Communications**	**1,588**	**1,849**	**2,884**

This subactivity funds telemetering improvements, technical support to protect cyber infrastructure, SCADA/EMS maintenance agreements, a communication alarm system replacement, an e-tagging system that electronically schedules power for customers, load forecasting, digital test equipment, fee for spectrum, and supplies and materials. The telemetering improvements include replacement of obsolete power and energy accounting equipment and modification of existing remote terminal units that improve the reliability of the power system, specifically in the areas of monitoring and control. Funding is required for upgrades that enable Southwestern to meet the goals of the EPACT, NEP, and DOE's Strategic Plan by replacing deteriorating infrastructure while assuring reliability and continuing to actively participate in the RTO. The funding level for communications maintenance is derived from maintenance history, the age of equipment, expected life span, annual diagnostic maintenance testing, and historical pricing information. The increase in funding of this subactivity reflects the communication alarm system replacement and additional telemetering improvements and maintenance agreements.

Frequency spectrum relocation activities are expected to be funded from spectrum auction proceeds, thus no funding is provided in this subactivity.

▪ **Environmental, Safety and Health**	**520**	**525**	**1,176**

This subactivity funds environmental activities including waste disposal/clean-up of oil and polychlorinated biphenyl contaminates from old circuit breakers and transformers; environmental assessments for threatened and endangered species; property transfers; wetland assessments; environmental library access; Toxic Substance Control Act and Resource Conservation Recovery Act compliance; contractor services; and requirements of the Environmental Protection Program as identified in DOE Order 450.1. Southwestern will also fund the Spill Prevention, Control, and Countermeasure (SPCC) Program, which will address oil containment requirements at Southwestern's substations. The Safety and Health Program activities require funding for Occupational Safety and Health Administration compliance, substation grounding and drainage, aviation safety, industrial hygiene, medical examinations, medical officer, wellness program, safety equipment, and first aid supplies. The increase in funding reflects the SPCC Program in compliance with oil pollution prevention requirements of 40 CFR 112 and substation grounding and drainage.

▪ **Other Transmission**	**436**	**460**	**261**

This subactivity funds physical security, field utility costs for substations and microwave sites, and the day-to-day expenses of the dispatch center. Southwestern completed vulnerability and risk assessments and its graded approach in applying risk mitigation strategies to determine security improvements of its critical assets; these improvements have been implemented. Simultaneously,

	(dollars in thousands)	
FY 2006	FY 2007	FY 2008

the Homeland Security Advisory System indicates there is no specific or credible intelligence suggesting an imminent threat to the homeland. Therefore, the decrease in funding for this subactivity is due to reduced physical security requirements.

	FY 2006	FY 2007	FY 2008
Maintenance	**3,992**	**3,811**	**6,204**

The Maintenance activity funds routine repair, maintenance, and improvement of Southwestern's 24 substations and 1,380 miles of high-voltage transmission lines, and assures power is reliably and safely delivered to customers. Southwestern's initial facilities, which were built approximately 60 years ago, are constantly evaluated through the maintenance management information system (MMIS). The funding level for this activity is derived from the MMIS (age, risk of failure, life cycle of equipment) and field crew evaluation. Internal and external factors include obsolescence of technology and lack of replacement parts. These variables are used in determining the level of funding required for a fiscal year. This budget request reflects Southwestern's assessment of the funding required to assure continued reliability of the Federal power system by replacing aging equipment and removing constraints that impede power flows, thus meeting the expectations of the NEP and DOE's Strategic Plan.

	FY 2006	FY 2007	FY 2008
▪ **Substation Maintenance**	**2,710**	**2,960**	**4,749**

This subactivity funds a transformer, power circuit breakers, disconnect switches, protective relays and related equipment, computer aided drafting and design, revenue meters, vehicle maintenance, fuel, and other equipment to perform general maintenance projects while maintaining system reliability as required by Southwestern's participation in a regional electric reliability council. The funding level for this subactivity is derived from MMIS data, which provides the age and condition of the existing equipment facilitating projection of maintenance intervals. The increase in funding for this subactivity reflects Southwestern's planned replacements in order to maintain reliability of the power system while accommodating increased loads on the Federal power facilities resulting from interconnection and open access requests from other utilities.

	FY 2006	FY 2007	FY 2008
▪ **Transmission Line Maintenance**	**1,282**	**851**	**1,455**

This subactivity funds the purchase of wood and steel structures, crossarms and braces, right-of-way (ROW) clearing, herbicide application, aerial patrol of the transmission system to identify maintenance needs, routine vehicle repair and maintenance, tractor-trailers, heavy equipment, and fuel. The quantity of steel and wood poles and crossarms and high voltage insulators is derived from MMIS data. Emphasis is being placed on ROW clearing since the North American Electric Reliability Corporation (NERC) identified improper/insufficient ROW clearing as a major factor in the August 2003 east coast Blackout. The funding level is appropriate for the number of structures and components to be replaced and the miles of ROW to be cleared as set forth by Southwestern's maintenance plans in meeting the goals of the EPACT and NEP to maintain a reliable transmission system. The increase in funding reflects ROW clearing equipment, steel crossarms and poles, and significantly increased cost of fuel for substation equipment.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Capitalized Movable Equipment	**0**	**300**	**425**

The Capitalized Movable Equipment activity funds the replacement of vehicles, tractor-trailers, and heavy equipment used for maintenance and repair of the transmission system and facilities. The replacement criteria Southwestern utilizes for specialized equipment needed to maintain 1,380 miles of transmission line is derived from the General Services Administration (GSA) and DOE guidelines based on operation duration and age. These vehicles exceed their useful lives and require high levels of maintenance. The vehicle cost estimates are derived from GSA pricing schedules. The increase in funding for this activity reflects the need to replace various types of special purpose vehicles.

Total, Operations and Maintenance	**6,972**	**7,145**	**11,978**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Power Marketing	
▪ Increase reflects funding for the control area boundary project.	+828
Operations	
▪ Increase reflects funding for communications equipment and related maintenance, the SPCC Program, and substation grounding and drainage.	+1,487
Maintenance	
▪ Increase reflects funding for a transformer, relay replacements, disconnect switches, ROW clearing equipment, and significantly increased fuel costs.	+2,393
Capitalized Movable Equipment	
▪ Increase reflects funding for replacement of special purpose vehicles.	+125
Total Funding Change, Operations and Maintenance	**+4,833**

Construction

Funding Schedule by Activity

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Construction			
Transmission System	2,901	3,612	4,300
Capital Equipment Not Related to Construction	233	0	0
Subtotal, Construction	3,134 [a]	3,612	4,300
Alternative Financing	n/a	n/a	-869
Total, Construction	3,134	3,612	3,431

Description

The mission of the Construction subprogram is to assure continued reliability of the Federal power system by providing for additions, modifications, replacements, and interconnections to the transmission, substation, and communication facilities, thus meeting the expectations of the 2005 Energy Policy Act (EPACT), National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects Southwestern Power Administration's (Southwestern) program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

Benefits

The activities of the Construction subprogram enable Southwestern to market and deliver Federal hydropower in the most reliable, safe, efficient, cost effective manner to meet the operational criteria required as a participant in the National electrical grid while avoiding transmission infrastructure deterioration. EPACT, NEP, and DOE's Strategic Plan reinforce the importance of renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past, current, and future energy supply and Southwestern's "important role in meeting demand" by supplying hydroelectric power to its customers. Southwestern's participation in the regional electric reliability council and the Regional Transmission Organization (RTO), encouraged by DOE's National Transmission Grid Study, reinforces Southwestern's role as an integral part of the Nation's interconnected generation and transmission system. As the demand for the transmission of power on the Nation's power systems increases, the need to provide improvements, replacements, and interconnections on the Federal power system, which require expansion of or additions to existing facilities, is critical in assuring reliable delivery.

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[a] Reflects a 1% rescission in accordance with Public Law No. 109-148, Emergency Supplemental Appropriations to Address Hurricanes in the Gulf of Mexico and Pandemic Influenza 2006, in the amount of $31,660.

Southwestern will continue to use appropriations and alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances) with customers and others who provide services or funds to assure a dependable and reliable Federal power system. Southwestern's authority to use net billing and bill crediting is inherent in the authority provided by the Flood Control Act of 1944, and has been affirmed by the Comptroller General.[a]

Southwestern's planned Construction projects are subject to change based on unanticipated equipment failure, customer needs, and weather conditions. The realities of maintaining a complex interconnected power system means unforeseen priority projects will arise periodically causing a reprioritization of planned projects. All projects share the commonality of replacing aging and deteriorating infrastructure necessary to maintain the reliability of the Federal power system.

Detailed Justification

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Transmission System	**2,901**	**3,612**	**4,300**

This activity funds all construction projects that require expansion of or additions to existing facilities. System reliability is assured by replacing aging and deteriorating equipment, thereby removing constraints that limit power flows. The projects reflect Southwestern's efforts to reduce the risk of extended service outages, avoid more costly replacements in the future, and support the increased transmission system usage. The funding level for this activity is derived from internal and external management decisions and maintenance crew observations regarding system age, risk of equipment failure, life cycles, obsolescence of technology, unavailable replacement parts, budget constraints, cost, and demand for more capacity. These variables are assessed and incorporated into Southwestern's 10-year construction plan.

	FY 2006	FY 2007	FY 2008
▪ **Substation Equipment**	**0**	**0**	**0**

This subactivity funds facility design work, installation of remote terminal units, substation metering, and telemetry equipment replacements.

	FY 2006	FY 2007	FY 2008
▪ **Communication Equipment**	**2,901**	**3,612**	**3,000**

This subactivity funds all communication equipment and microwave radio and tower replacements that are planned to provide improved system reliability and reduce future maintenance and equipment costs. This subactivity also provides funding for microwave radios and microwave tower additions, replacements, and modifications that will allow Southwestern to complete an important communication ring within its network that will increase the reliability of communications with the generating plants and substations in the Oklahoma region. The communication system provides for the transfer of voice and data traffic to allow monitoring and control of power system generation and transmission assets. The decrease in funding for FY 2008 reflects the reduced number of planned microwave radio and tower replacements.

In December 2004, the Congress passed and the President signed the Commercial Spectrum

[a] Honorable Secretary of the Interior B-125, 127 (February 14, 1956) available at WL 3064 (Comp. Gen.).

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Enhancement Act (CSEA, Title II of P.L. 108-494), creating the Spectrum Relocation Fund (SRF) to streamline the relocation of Federal systems from certain spectrum bands to accommodate commercial use by facilitating reimbursement to affected agencies of relocation costs. The Federal Communications Commission has auctioned licenses for reallocated Federal spectrum, which will facilitate the provision of Advanced Wireless Services to consumers. Funds are made available to agencies in fiscal year 2007 for relocation of communications systems operating on the affected spectrum. Southwestern estimates $8.1 million in relocation costs, as approved by the Office of Management and Budget, and as reported to the Congress by the Department of Commerce in December 2005. These funds are mandatory and will remain available until expended, and agencies will return to the SRF any amounts received in excess of actual relocation costs. Frequency spectrum activities are expected to be funded from spectrum auction proceeds, thus no funding is provided in this subactivity.			
▪ **Transmission Upgrades**	**0**	**0**	**1,300**
This subactivity funds transmission system upgrades as mandated by the RTO. The RTO in Southwestern's marketing area performed a system impact study that resulted in the requirement to re-conductor the Idalia-Asherville line. This will improve the transmission infrastructure by alleviating power flow constraints and eliminating line overloading as required under DOE's National Transmission Grid Study and the NEP.			
Capital Equipment Not Related to Construction	**233**	**0**	**0**
This activity funds the replacement of vehicles used for maintenance and repair of the transmission system and facilities. The replacement criteria Southwestern utilizes for specialized equipment needed to maintain 1,380 miles of transmission line is derived from the General Services Administration (GSA) and DOE guidelines based on operation duration and age. These vehicles exceed their useful lives and require high levels of maintenance. The vehicle cost estimates are derived from GSA pricing schedules. This activity was transferred to the Operations and Maintenance subprogram in FY 2007 to be consistent with the vehicles' purpose.			
Total, Construction	**3,134**	**3,612**	**4,300**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Transmission System	
▪ The net increase in funding reflects funding to re-conductor the Idalia-Asherville line offset by reductions in planned communication equipment.	+688
Total Funding Change, Construction	**+688**

Purchased Power and Wheeling

Funding Schedule by Activity

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Purchased Power and Wheeling (PPW) [a]			
System Support	9,100	10,300	41,500
Other Contractual Services	3,300	3,300	3,500
Total, PPW (gross)	12,400	13,600	45,000 [b]
Use of Alternative Financing – Reimbursable Authority (customer advances), Net Billing, Bill Crediting:			
Purchased Power	-2,825	-3,825	-3,425
Power Losses	-3,300	-3,500	-3,300
Wheeling	-3,275	-3,275	-3,275
Total, Alternative Financing	-9,400	-10,600	-10,000
Subtotal, PPW	3,000	3,000	35,000
Offsetting Collections	-3,000	-3,000	-35,000
Total, Purchased Power and Wheeling	0	0	0

Description

The mission of the Purchased Power and Wheeling (PPW) subprogram is to provide for the purchase of energy to meet limited peaking power contractual obligations and the delivery of Federal power. Such purchases are blended with the available Federal hydroelectric power and energy to make a more beneficial and reliable product while assuring repayment of the Federal investment plus interest, thus meeting the expectations of the 2005 Energy Policy Act (EPACT), National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects Southwestern Power Administration's (Southwestern) program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

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[a] The Continuing Fund presently codified at 16 U.S.C. 825s-1, as amended by Public Law No. 101-101, will continue to be used to defray emergency expenses to ensure continuity of electric service. Actual Continuing Fund usage for FY 2005 and FY 2006 was $2,094,926 and $62,790,362, respectively.

[b] Southwestern's FY 2008 PPW budget request reflects an increase in authority to use Federal power receipts for anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested.

Benefits

The activities of the PPW subprogram provide for the purchase of energy to meet limited peaking power contractual obligations to assure the marketability of the Federal resource and repayment of the Federal investment. Southwestern's power sales contracts provide for only 1200 hours of peaking power per year, representing a portion of its customers' firm load requirements. The customers provide their own resources and/or purchases for the remainder of their firm loads. This subprogram also provides for wheeling services that deliver Federal power to optimize the operation of the hydroelectric facilities marketed by Southwestern. EPACT, NEP, and DOE's Strategic Plan reinforce the importance of domestic, renewable hydroelectric energy by emphasizing its ongoing significant contribution to the Nation's past, current, and future energy supply and Southwestern's "important role in meeting demand" by supplying hydroelectric power to its customers.

The reduced level of energy banking available from other electric utilities requires Southwestern to use alternative financing to fund power deliveries. Southwestern will continue to use Federal power receipts and alternative financing methods, including net billing, bill crediting, and/or reimbursable authority (customer advances) to fund this subprogram. When hydro generation is significantly below-normal due to severe drought conditions, Southwestern will utilize the Continuing Fund to defray emergency expenses to ensure continuity of electric service.

Detailed Justification

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
System Support	**9,100**	**10,300**	**41,500**

This activity funds purchased power requirements that fulfill all 1200-hour contractual peaking power obligations with customers. In addition, energy purchases must be provided for replacement of transmission line losses associated with the delivery of non-Federal power over the Federal transmission system as required under Federal Energy Regulatory Commission (FERC) Order 888. Southwestern will continue to deliver limited peaking power and provide for power losses through power purchases. Southwestern will continue to use Federal power receipts and alternative financing methods, including net billing, bill crediting, and/or reimbursable authority (customer advances) to meet purchased power requirements.

System support requirements are affected by weather, volatile market prices, and limited availability of energy banks. For the past 20 years, Southwestern's purchased power requirements have been based on average water conditions, which were established in an effort to reduce unused appropriations during numerous good water years. However, since 2001, Southwestern has received authority from Congress to use its receipts to fund purchases, again based on average water conditions. Recent drought conditions in Southwestern's service area have pointed out problems with the limitation on use of receipts to average water conditions, including constant requests for use of the Continuing Fund. In order to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations under all but the most severe hydrological conditions, Southwestern is requesting an increase in authority to use Federal power receipts. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested. Since the rates charged to its customers are based on costs, Southwestern has a built-in incentive to minimize its expenditures for purchased power. This increase in authority will ensure greater flexibility in times of

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

below average generation and volatile market prices, and will decrease dependence on the continuing fund.

Other Contractual Services	**3,300**	**3,300**	**3,500**

This activity funds other contractual services that provide for wheeling associated with the purchase of transmission service to meet limited peaking power obligations and for the integration of projects for the delivery of Federal power. The funding level for this activity is derived from contractual wheeling requirements. Southwestern will continue to use Federal power receipts and alternative financing methods, including net billing, bill crediting, and/or reimbursable authority (customer advances) to meet wheeling requirements. The increase in funding is due to projected cost for wheeling services based on contractual pricing and delivery terms.

Total, Purchased Power and Wheeling	**12,400**	**13,600**	**45,000**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
System Support	
▪ Increase in system support reflects anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested.	+31,200
Other Contractual Services	
▪ Increase in other contractual services reflects projected cost for wheeling services based on contractual pricing and delivery terms.	+200
Total Funding Change, Purchased Power and Wheeling	**+31,400**

Program Direction

Funding Profile by Category

	(dollars in thousands/whole FTEs)		
	FY 2006	FY 2007	FY 2008
Program Direction (PD)			
Salaries and Benefits	16,255	17,150	18,300
Travel	629	665	700
Support Services	1,351	1,422	1,469
Other Related Expenses	1,523	1,545	1,745
Subtotal, Program Direction	19,758 [a]	20,782	22,214
Alternative Financing	n/a	n/a	-877
Total, Program Direction	19,758	20,782	21,337
Full time Equivalents	171	179	179

Mission

The mission of the Program Direction subprogram is to assure continued reliability of the Federal power system by utilizing Federal staffing resources and associated funds required to provide overall direction and execution of Southwestern Power Administration's (Southwestern) Operation and Maintenance Program. This subprogram supports the 2005 Energy Policy Act (EPACT), the National Energy Policy (NEP), and the Department of Energy's (DOE) Strategic Plan by providing delivery of reliable, affordable, and environmentally sound energy to the Nation. This subprogram fulfills the requirements of Section 5 of the Flood Control Act of 1944 and reflects Southwestern's program goal to provide the benefits of Federal power to customers by selling and reliably delivering power from Federal multipurpose hydroelectric dams at the lowest cost-based rates possible that produce revenues sufficient to repay all power costs to the American taxpayers.

As stated in the Departmental Strategic Plan, DOE's Strategic Goals will be accomplished not only through the efforts of the major program offices in DOE, but also with additional effort from offices which support the programs in carrying out the mission. The Program Direction subprogram provides compensation and all related expenses for 179 Federal personnel, who market, deliver, operate, and maintain Southwestern's high-voltage interconnected power system and associated facilities. Southwestern will use appropriations for capital investments, appropriations offset by receipts for non-capital annual expenses, and continue to use alternative financing arrangements, including net billing, bill crediting, and/or reimbursable authority (customer advances) with customers and others who provide services or funds to assure a dependable and reliable Federal power system. Southwestern's authority to use net billing and bill crediting is inherent in the authority provided by the Flood Control Act of 1944, and has been affirmed by the Comptroller General.[b]

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[a] Reflects a 1% rescission in accordance with Public Law No. 109-148, Emergency Supplemental Appropriations to Address Hurricanes in the Gulf of Mexico and Pandemic Influenza 2006, in the amount of $199,580.
[a] Honorable Secretary of the Interior B-125, 127 (February 14, 1956) available at WL 3064 (Comp. Gen.).

Southwestern performs critical functions in meeting the challenges of operating and maintaining the Federal power system to assure reliability, while meeting the growing demand for power and avoiding deterioration of the infrastructure. The functions include managing information technology, ensuring sound legal advice and fiscal stewardship, developing and implementing uniform program policy and procedures, maintaining and supporting our workforce, safeguarding our facilities, and providing Congressional and public liaison.

Southwestern is committed to performing its mission while supporting the initiatives of the President's Management Agenda. Southwestern assessed its performance in all five initiatives of the President's Management Agenda [Strategic Management of Human Capital, Expanded Electronic Government (E-Government), Competitive Sourcing, Improved Financial Performance, and Budget and Performance Integration] and is "Green" in all four relevant initiatives.

Southwestern's Program Direction subprogram further supports the Human Capital initiative, which is linked with careful planning and administration of the budget, through its Human Capital Management (HCM) Workforce Plan. This linkage is manifested in planning to assure that funds are available and allocated properly to support the initiative's elements. HCM Workforce Plan requirements include: reducing the number of organizational layers, addressing succession planning, reducing the time to make decisions, redirecting positions to the front lines, improving operational processes, and addressing other key workforce challenges.

By the end of FY 2008, approximately 35 percent of Southwestern's staff will be eligible for retirement. However, Southwestern will retain a strong staff of professionals dedicated to the pursuit of excellence by continuing to invest in its current employees, emphasize strong development programs, complete skills gap analyses, and pursue aggressive recruitment and retention efforts as identified in its HCM Workforce Plan.

Southwestern continues to share facilities and administrative services with another DOE office at Southwestern's Tulsa Headquarters facility. This arrangement is cost efficient and beneficial for both organizations.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Salaries and Benefits	**16,255**	**17,150**	**18,300**

This activity funds salaries and benefits for 179 skilled Federal employees, who market and deliver Federal hydropower by operating and maintaining Southwestern's high-voltage interconnected power system with its associated facilities and providing support for these functions. The funding level for salaries is derived from the current year budgeted salaries plus cost-of-living adjustments, promotions, and within grade increases. The funding level for benefits is derived from a percentage of budgeted salaries. Annual benefit costs continue to increase faster than salaries due to rising health insurance premiums and the higher cost of an increasing number of FERS employees relative to CSRS employees.

The FY 2008 level supports 179 FTE: 55 percent of the employees are General Schedule (GS) and subject to the President's proposed 2.2 percent cost of living adjustment; salaries of the remaining 45 percent (craft workers and power system dispatchers) are determined through union negotiations and

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

wage surveys. This activity also includes overtime, awards, relocation, workers' compensation, recruitment bonuses, retention pay, and advanced in-hire rates. The increase in funding is due to cost of living adjustments and significantly-rising benefit costs.

	FY 2006	FY 2007	FY 2008
Travel	**629**	**665**	**700**

This activity funds all related travel and per diem expenses incurred in the operation and maintenance of Southwestern's geographically dispersed power system. The funding level for this activity is primarily derived from the daily requirement of the field maintenance personnel to maintain 1,380 miles of transmission line, 24 substations, 47 microwave/radio sites, communication equipment, and the Supervisory Control and Data Acquisition network.

This activity includes travel related to participation with the regional electric reliability council and Regional Transmission Organization to establish procedures for providing regional power restoration assistance to other non-hydropower generation sources during outage emergencies. Travel for E-Government-related initiatives and performance of general and administrative functions is also included. The increase in funding for this activity is due to rising per diem, transportation rates, and significantly increased fuel costs for mission-related travel to maintain the integrity and reliability of the integrated electrical grid.

	FY 2006	FY 2007	FY 2008
Support Services	**1,351**	**1,422**	**1,469**

This activity funds contracted management support services including information technology, E-Government, and administrative/records management support. The funding level for this activity is derived from the most recent negotiated contract for support services essential to achieve Southwestern's mission. The increase in funding for this activity reflects the terms of the negotiated contract.

	FY 2006	FY 2007	FY 2008
Other Related Expenses	**1,523**	**1,545**	**1,745**

This activity funds DOE's working capital distribution, rental space, printing and reproduction, training tuition, maintenance of office equipment, supplies and materials, employee parking, janitorial services, Equal Employment Opportunity investigations, Power Marketing Liaison Office (PMLO) services, financial audit, A-123 requirements, and GovTrip. Intermittent specialized services, not included in ongoing support service contracts, are also included. Rental space costs assume the GSA inflation factor. Other costs are based on the historical usage and actual cost of similar items. The increase in funding for this activity is primarily due to the terms of the negotiated contract for rental space, the financial audit, and the PMLO expenses.

	FY 2006	FY 2007	FY 2008
Total, Program Direction	**19,758**	**20,782**	**22,214**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Salaries and Benefits	
▪ Increase in salaries and benefits reflects wage survey-based, union-negotiated, and Administratively Determined pay adjustments, and a 2.2% cost of living adjustment for GS employees. Payroll benefits are increasing at a rate in excess of salaries.	+1,150
Travel	
▪ Increase reflects rising per diem rates and significantly increased fuel costs for mission-related travel to maintain the transmission system.	+35
Support Services	
▪ Increase reflects funding for support services per the negotiated contract.	+47
Other Related Expenses	
▪ Increase in mandatory training	+43
▪ Decrease in printing and reproduction	-2
▪ Increase in rental space costs due to the terms of the negotiated contract	+40
▪ Decrease in employee parking costs	-19
▪ Increase in financial audit per contractual terms	+13
▪ Increase in security supplies	+31
▪ Increase in other expenses	+94
Total, Other Related Expenses	+200
Total Funding Change, Program Direction	**+1,432**

Support Services by Category

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Management Support			
Reports and Analysis Management and General Administrative Services	1,351	1,422	1,469
Total, Management Support	1,351	1,422	1,469
Total, Support Services	1,351	1,422	1,469

Other Related Expenses by Category

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Other Related Expenses			
Training	77	54	97
Printing and Reproduction	40	41	39
Rent to Others	550	593	633
Employee Parking	106	103	84
Financial Audit	205	267	280
Power Marketing Liaison Office	140	140	140
Security Supplies	0	0	31
Other	405	347	441
Total, Other Related Expenses	1,523	1,545	1,745

Revenues and Receipts

(dollars in thousands)

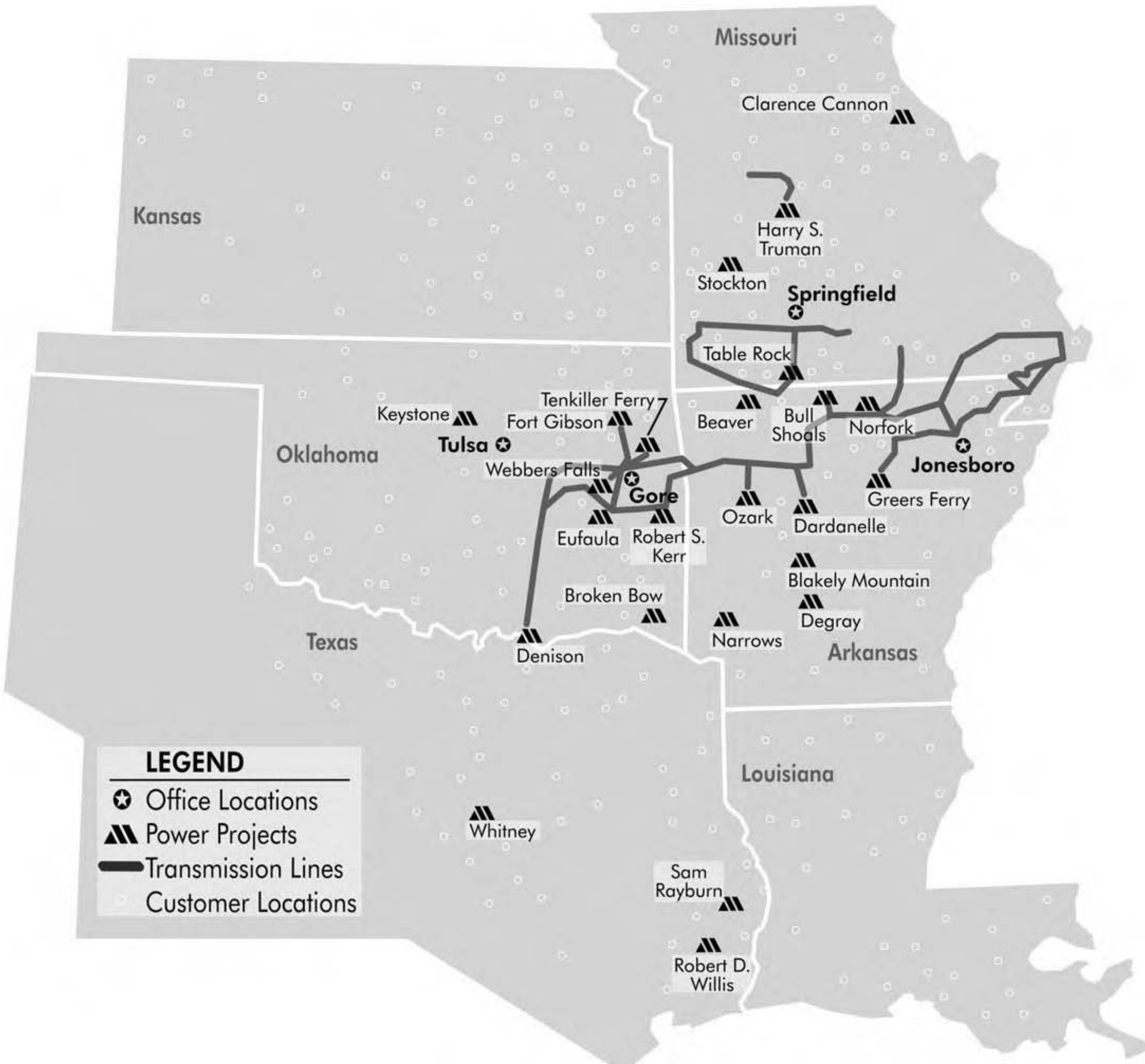
	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Gross Revenues							
Sale and Transmission of Electric Energy	116,400	162,500 [a]	180,900	189,800	190,300	191,000	192,000
Agency Rate Proposal [b]	0	1,900	1,900	1,900	1,900	1,900	1,900
Total, Gross Revenues	116,400	164,400	182,800	191,700	192,200	192,900	193,900
Alternative Financing Credited as an Offsetting Receipt	-38,173	-52,100	-63,900	-63,200	-63,900	-65,000	-63,900
Offsetting Collections Realized, Purchased Power and Wheeling (PPW)[c]	-3,000	-3,000	-35,000	-36,000	-37,000	-38,000	-39,000
Continuing Fund Usage for PPW [d]	-62,790	0	0	0	0	0	0
Total Proprietary Receipts	12,437	109,300	83,900	92,500	91,300	89,900	91,000
Percent of Sales to Preference Customers	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Energy Sales and Power Marketed (billion kilowatt hours)	5.4	5.4	5.4	5.4	5.4	5.4	5.4

[a] Reflects an increase in revenues due to a rate increase to cover purchased power costs.
[b] The budget provides that the interest rate for future obligations owed to the Treasury by Southwestern for power-related investments be set at the rate Governmental corporations borrow in the market, similar to the interest rates current law sets for Bonneville Power Administration's borrowing from the Treasury. This new policy will be applied to all power-related investments occurring after September 30, 2006, whose interest rates are not specified in law.
[c] Reflects an increase in use of receipts for purchased power and wheeling activities based on anticipated needs to ensure adequate funding to fulfill its 1200-hour peaking power contractual obligations based on volatile market prices, limited availability of energy banks, and all but the most severe hydrological conditions. The use of this increased authority will be dependent upon the hydrological conditions of that fiscal year which, under average conditions, will be approximately half of the authority requested.
[d] The Continuing Fund was activated in FY 2005 and FY 2006 due to continued drought conditions.

System Statistics

	FY 2006 Actual	FY 2007 Estimate	FY 2008 Estimate	FY 2009 Estimate	FY 2010 Estimate	FY 2011 Estimate	FY 2012 Estimate
Generating Capacity (kilowatts)							
Installed Capacity	2,181,800	2,181,800	2,181,800	2,181,800	2,181,800	2,181,800	2,181,800
Peak Capacity	2,052,538	2,052,500	2,052,500	2,052,500	2,052,500	2,052,500	2,052,500
Generating Stations							
Generating Projects (Number)	24	24	24	24	24	24	24
Substations/Switchyards (Number)	24	24	24	24	24	24	24
Substations/Switchyards (kVA Capacity)	1,026,900	1,026,900	1,026,900	1,026,900	1,026,900	1,026,900	1,026,900
Available Energy (Megawatt-hours)							
Energy Generated	1,535,581	5,412,400	5,430,700	5,416,700	5,419,100	5,419,100	5,419,100
Energy Received	883,126	186,700	203,100	207,400	207,500	207,500	207,500
Total, Energy Available for Marketing	2,418,707	5,599,100	5,633,800	5,624,100	5,626,600	5,626,600	5,626,600
Transmission Lines (Circuit-Miles)							
161-KV	1,117	1,117	1,117	1,117	1,117	1,117	1,117
138-KV	164	164	164	164	164	164	164
69-KV	99	99	99	99	99	99	99
Total, Transmission Lines	1,380	1,380	1,380	1,380	1,380	1,380	1,380

System Map


Missouri
Clarence Cannon
Harry S. Truman
Stockton
Springfield
Table Rock
Kansas
Oklahoma
Keystone
Tulsa
Tenkiller Ferry
Fort Gibson
Webbers Falls
Gore
Eufaula
Robert S. Kerr
Beaver
Bull Shoals
Norfork
Jonesboro
Greers Ferry
Ozark
Dardanelle
Blakely Mountain
Degray
Narrows
Arkansas
Broken Bow
Denison
Texas
Louisiana
Whitney
Sam Rayburn
Robert D. Willis
LEGEND
Office Locations
Power Projects
Transmission Lines
Customer Locations

Power Marketed, Wheeled, or Exchanged By Project

	State	Number of Plants	Installed Capacity (kW)	FY 2006 Actual Energy (GWh)	FY 2007 Estimated Energy (GWh)	FY 2008 Estimated Energy (GWh)	FY 2009 Estimated Energy (GWh)	FY 2010 Estimated Energy (GWh)	FY 2011 Estimated Energy (GWh)	FY 2012 Estimated Energy (GWh)
Power Marketed										
Interconnected										
System	Missouri	4	463,200	724	1,666	1,680	1,677	1,677	1,677	1,677
	Arkansas	9	1,045,100	433	997	1,005	1,004	1,004	1,004	1,004
	Oklahoma	7	514,100	506	1,164	1,174	1,172	1,172	1,172	1,172
	Texas	2	100,000	236	542	547	546	546	546	546
	Louisiana	0	0	183	421	424	424	424	424	424
	Kansas	0	0	187	430	433	433	433	433	433
Subtotals		22	2,122,400	2,269	5,220	5,263	5,256	5,256	5,256	5,256
Isolated:										
Robert D. Willis Project										
Sam Rayburn Project										
50% to Texas		2	59,400	42	76	76	76	76	76	76
50% to Louisiana		0	0	13	76	76	76	76	76	76
Subtotals		2	59,400	55	152	152	152	152	152	152
Total, Power Marketed		24	2,181,800	2,324	5,372	5,415	5,408	5,408	5,408	5,408
Power Wheeled/Exchanged										
Wheeled (MW)				1,072	1,086	1,106	1,117	1,129	1,129	1,129
Exchanged (GWh)				195	0	0	0	0	0	0

Pending Litigation

Southwestern Power Administration (Southwestern) has no pending court litigation, as of December 19, 2006. Southwestern presently has the following administrative litigation pending before the Federal Energy Regulatory Commission (FERC):

> Southwestern filed revisions to its non-jurisdictional Open Access Transmission Tariff (OATT) on January 25, 2006. FERC approved the Southwestern OATT March 21, 2006, on the condition that Southwestern achieves formal compliance with Orders 2003 and 2006. Southwestern filed a Request for Clarification, Waiver, Rehearing, or Declaratory Order on April 19, 2006. FERC filed an Order Granting Rehearing for Further Consideration on May 19, 2006; however, the Commission took no action within 30 days and the request was deemed denied. On August 29, 2006, FERC denied Southwestern's request to waive the rights of Order Nos. 2003 and 2006.

Southwestern is an intervener in the following actions pending before FERC:

> P-459-128, Union Electric Ameren (UA) - UA requested a license for a major project for the Osage project existing dam. Southwestern filed a Motion to Intervene on April 27, 2004.

> RR06-1, North American Electric Reliability Council and North American Electric Reliability Corporation (NERC) – NERC filed a request for certification as the Electric Reliability Organization. Southwestern filed a Motion to Intervene Out-of-Time to protect status interests as an owner of transmission facilities, substation facilities, and other facilities.
> FERC issued an order on July 20, 2006, certifying North American Reliability Corporation as the electric reliability organization and ordering compliance filing.

Southwestern has one tort claim pending.

Southwestern has two EEO claims pending.

Southwestern management believes the possibility of incurring financially material liability in any of these matters is remote.

Estimates for Historically Black Colleges and Universities

(dollars in thousands)

Appropriation/Decision Unit	Name of HBCU (if known)	FY 2006 BA	FY 2007 BA	FY 2008 BA Request	FY 2009 BA Request	FY 2010 BA Request	FY 2011 BA Request	FY 2012 BA Request
Southwestern Power Administration, Operation and Maintenance	(to be determined)	15	15	15	15	15	15	15
Subtotal, Southwestern Power Administration 89X0303		15	15	15	15	15	15	15
Total, Southwestern Power Administration		15	15	15	15	15	15	15

Program Contact:

Name: Cheryl Crosswell

Telephone: (918) 595-6616

Western Power Administration

Western Power Administration

Construction, Rehabilitation, Operation and Maintenance
Western Area Power Administration

Proposed Appropriation Language

For carrying out the functions authorized by title III, section 302(a)(1)(E) of the Act of August 4, 1977 (42 U.S.C. 7152), and other related activities including conservation and renewable resources programs as authorized, including the operation, maintenance, and purchase through transfer, exchange, or sale of one helicopter for replacement only, and official reception and representation expenses in an amount not to exceed $1,500; $201,030,000, to remain available until expended, of which $191,094,000 shall be derived from the Department of the Interior Reclamation Fund: Provided, That of the amount herein appropriated, $7,167,000 is for deposit into the Utah Reclamation Mitigation and Conservation Account pursuant to title IV of the Reclamation Projects Authorization and Adjustment Act of 1992: Provided further, That notwithstanding the provision of 31 U.S.C. 3302, up to $258,702,000 collected by the Western Area Power Administration pursuant to the Flood Control Act of 1944 and the Reclamation Project Act of 1939 to recover purchase power and wheeling expenses shall be credited to this account as offsetting collections, to remain available until expended for the sole purpose of making purchase power and wheeling expenditures.

Falcon and Amistad Operating and Maintenance Fund

Proposed Appropriation Language

For operation, maintenance, and emergency costs for the hydroelectric facilities at the Falcon and Amistad Dams, $2,500,000, to remain available until expended, and to be derived from the Falcon and Amistad Operating and Maintenance Fund of the Western Area Power Administration, as provided in section 423 of the Foreign Relations Authorization Act, Fiscal Years 1994 and 1995.

Western Area Power Administration

Overview

Appropriation Summary by Program

	(dollars in thousands)			
	FY 2006 Current Appropriation[a]	FY 2007 Request	FY 2007 CR	FY 2008 Request
Western Area Power Administration Accounts				
Construction, Rehabilitation, Operation and Maintenance (CROM) Account (Operating Expenses) (Gross)[b]	572,949	688,511	688,511	705,911
Less Use of Alternative Financing	-58,135	-197,741	-193,593	-242,242
Offsetting Collections from Colorado River Dam Fund (P.L. 98-381)	-4,162	-3,705	-3,705	-3,937
Offsetting Collections, Purchase Power and Wheeling (PPW) expenses	-279,000	-274,852	-279,000	-258,702
Total, CROM Account (Budget Authority)	231,652	212,213	212,213	201,030
Total, Falcon and Amistad Operating and Maintenance Fund (Budget Authority)	2,665	2,500	2,500	2,500
Colorado River Basins Power Marketing Fund (CRBPMF) (Operating Expenses)	192,281	221,081	221,081	232,145
Offsetting Collections Realized	-192,281	-244,081	-244,081	-255,145
Total, CRBPMF (Budget Authority)	0	-23,000	-23,000	-23,000
Total, Western Area Power Administration	234,317	191,713	191,713	180,530

Preface

The Department of Energy (DOE) leads a critical effort to strengthen national and economic security, in promoting a diverse supply of reliable, affordable and environmentally-sound energy. Western Area Power Administration (Western), in conjunction with the U.S. Army Corps of Engineers (Corps), the U.S. Bureau of Reclamation (BOR) and the Department of State's International Boundary and Water Commission (IBWC), strongly supports this effort in managing the multipurpose operation of the Federal hydropower system to reliably deliver renewable energy across a high-voltage, integrated transmission system.

Within the three appropriation accounts (e.g. Construction, Rehabilitation, Operation and Maintenance Account (CROM), the Falcon and Amistad Operating and Maintenance Fund, and the Colorado River Basins Power Marketing Fund (CRBPMF)), there is one program: the Western Area Power

[a] FY 2006 reflects the general 1.00 percent across-the-board rescission of $2,339,920 to the CROM account, and $26,920 to the Falcon and Amistad account (P.L. 109-148).

[b] FY 2006, FY 2007 request, and FY 2008 CROM funding amounts include $42,397,000, $153,079,000, and $166,552,000 respectively, for planned alternative financing of the PPW subprogram; including use of Western's Continuing Fund as necessary to respond to below normal hydropower generation conditions. In addition, the FY 2006, requested FY 2007, and FY 2008 CROM funding amounts include $15,738,000, $44,662,000, and $75,690,000 respectively, for planned alternative financing of Western's Operation & Maintenance, Construction and Rehabilitation, and Program Direction subprograms.

Administration. Within Western, there are a total of eight subprograms; five in the CROM Account, one in the Falcon and Amistad Operating and Maintenance Fund and two in CRBPMF.

Mission
Western markets and delivers reliable, cost-based Federal hydroelectric power and related services throughout the central and western United States.

Benefits
Western's marketing efforts and delivery capability span a 1.3-million-square-mile area serving a diverse group of approximately 750 wholesale customers, including municipalities, cooperatives, public utility and irrigation districts, Federal and State agencies and Native American tribes. In turn, wholesale power is used to provide service to millions of retail consumers.

Strategic Themes and Goals and GPRA Unit Program Goals
The Department's Strategic Plan identifies five Strategic Themes (one each for nuclear, energy, science, management, and environmental aspects of the mission) plus 16 Strategic Goals that tie to the Strategic Themes. The Western appropriations support the following goals:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3, Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

The Western program funded within the CROM Account, Falcon and Amistad Operating and Maintenance Fund, and CRBPMF has one GPRA Unit Program Goal that contributes to this strategic goal in the "goal cascade." This goal is:

GPRA Unit Program Goal 1.3.17: Market and reliably deliver Federal power to customers.

Contribution to Strategic Goal
Western, through its three accounts (CROM, Falcon and Amistad Operating and Maintenance Fund and CRBPMF), contributes to Strategic Goal 1.3, Energy Infrastructure, by performing its mission in a manner that promotes higher capacity U.S. energy infrastructure and ensures flexible reliable operations and efficient markets. Specifically, Western is incrementally improving its facilities to increase transmission capacity and enhance grid reliability to support continuing utility industry change, requests for interconnections to the Federal system, and evolving regional needs such as increased interest in renewable resources. Western also jointly plans, develops, and finances system enhancements, encouraging partnerships for transmission development and fostering cooperation and economic coordination among transmission partners.

Funding by Strategic and GPRA Unit Program Goal

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Strategic Goal 1.3, Energy Infrastructure			
GPRA Unit Program Goal 1.3.17, Western Area Power Administration Accounts			
Construction, Rehabilitation, Operation and Maintenance Account	572,949	688,511	705,911
Falcon and Amistad Operating and Maintenance Fund	2,665	2,500	2,500
Colorado River Basins Power Marketing Fund Operating Expenses	192,281	221,081	232,145
Total, Strategic Goal 1.3 (Western Area Power Administration Accounts)	767,895	912,092	940,556

Annual Performance Results and Targets

Strategic Goal 1.3, Energy Infrastructure

Western Area Power Administration

FY 2003 Results	FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets
Transmission System Performance: Ensure that each power system control area operated by a PMA receives, for each month of the fiscal year, a Control Compliance Rating of “Pass” using the North American Electric Reliability Council performance standard. (MET GOAL) Actual: CPS1: 185.6 CPS2: 98.1 Industry average: CPS1: 169.1 CPS2: 96.5	System Reliability Performance: The target is to attain monthly NERC compliance ratings of 100 or higher for Control Performance Standard (CPS) 1 and a rating of 90 or above for CPS2. (MET GOAL) Actual: CPS1:184.0 CPS2:98.3 Industry average: CPS1: 165.1 CPS2: 96.7	System Reliability Performance: Attain acceptable North American Electric Reliability Council (NERC) ratings for the following Control Performance Standards (CPS) measuring the balance between power generation and load: 1) CPS1 which measures generation/load balance and support system frequency on one minute intervals (rating>100); and 2) CPS2 which limits any imbalance magnitude to acceptable levels (rating>90). (MET GOAL) Actual: CPS1: 183.9 CPS2: 98.2 Industry average: CPS1: 161.4 CPS2: 95.9	System Reliability Performance: Attain acceptable North American Electric Reliability Council (NERC) ratings for the following Control Performance Standards (CPS) measuring the balance between power generation and load: 1) CPS1 which measures generation/load balance and support system frequency on one minute intervals (rating>100); and 2) CPS2 which limits any imbalance magnitude to acceptable levels (rating>90). Actual: CPS1: 184.4 CPS2: 98.7 Industry average: CPS1: 161.5 CPS2: 97.0	System Reliability Performance: Attain acceptable North American Electric Reliability Council (NERC) ratings for the following Control Performance Standards (CPS) measuring the balance between power generation and load: 1) CPS1 which measures generation/load balance and support system frequency on one minute intervals (rating>100); and 2) CPS2 which limits any imbalance magnitude to acceptable levels (rating>90).	System Reliability Performance: Attain acceptable North American Electric Reliability Council (NERC) ratings for the following Control Performance Standards (CPS) measuring the balance between power generation and load: 1) CPS1 which measures generation/load balance and support system frequency on one minute intervals (rating>100); and 2) CPS2 which limits any imbalance magnitude to acceptable levels (rating>90).
	System Reliability Performance: Accountable customer and/or transmission element outages will not exceed the average number of outages for the past five years. (MET GOAL) Goal: <= 26 outages Actual: 21	System Reliability Performance: Accountable customer and/or transmission element outages will not exceed the average number of outages for the past five years. (MET GOAL) Goal: <= 23 outages Actual: 23		System Reliability Performance: Limit accountable customer and/or transmission element outages. Goal: <= 26 outages	System Reliability Performance: Limit accountable customer and/or transmission element outages. Goal: <= 26 outages
		System Reliability Performance: Maintain ratio of unanticipated repair work hours to total maintenance hours at 16% or less. (MET GOAL) Actual: 7.1%			

FY 2003 Results	FY 2004 Results	FY 2005 Results	FY 2006 Results	FY 2007 Targets	FY 2008 Targets
Repayment of Federal Power Investment: Meet planned repayment of principal on power investment. (MET GOAL) Goal: $24.9 M Actual: $32.2 M	Repayment of Federal Power Investment: Meet planned annual repayment of principal on Federal power investment. (MET GOAL) Goal: $31.9 M Actual: $93.6M				
		Repayment of Power Investment: Ensure unpaid investment is equal to or less than the allowable unpaid investment. Achieve a ratio of unpaid to allowable unpaid <= 1.00. (MET GOAL) Actual: 1.0		Repayment of Power Investment: Ensure unpaid investment is equal to or less than the allowable unpaid investment. Achieve a ratio of unpaid to allowable unpaid <= 1.00.	Repayment of Power Investment: Ensure unpaid investment is equal to or less than the allowable unpaid investment. Achieve a ratio of unpaid to allowable unpaid <= 1.00.
Safety: Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of 3.3 or less, or the latest published Bureau of Labor Statistics' industry rate, whichever is lower. (MET GOAL) Actual: 2.5 Industry: 5.0	Recordable Accident Frequency Rate: Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3, or the latest published Bureau of Labor Statistics' industry rate, whichever is lower. (MET GOAL) Actual: 1.6 Industry: 4.9	Recordable Accident Frequency Rate: Achieve a recordable accident frequency rate for recordable injuries per 200,000 hours worked of not greater than 3.3. (MET GOAL) Actual 1.6			

Means and Strategies

Western will use various means and strategies, outlined below, to achieve its GPRA Unit Program goal to ensure customers continue to receive maximum benefit from the Federal hydropower program. Various external factors are also shown which may impact Western's ability to achieve this goal. In addition, Western also requires the collaborative support of its Federal hydropower partners to help achieve its goal.

Western will implement the following means:

- Improve the capability, performance and reliability of the integrated grid through technology and equipment enhancements.

- Improve workforce analytical capabilities and employee skills; hiring, training, and retaining a high-performing team to carryout the agency's mission.

Western will continue the following strategies:

- Ensure efficient transmission system operations to support the integrated nature of the Nation's power grid.

- Maintain and modernize systems and infrastructure to increase the reliability, efficiency, and use of Federal assets.

- Use sound business practices and prudent risk management in the conduct of agency activities and operations.

The following external factors could affect Western's ability to achieve its goal:

- System reliability can be affected by weather, natural disasters, changes in North American Electric Reliability Council (NERC) operation standards, industry deregulation, load growth, changing electric industry organizational structures, interconnections, open access and the lack of adequate funding resources.

Successful collaboration of the Federal hydropower partners is necessary for Western to achieve its goals. We coordinate our operational activities with the Corps, BOR, IBWC, customers, and regional utilities to provide the most efficient use of Federal assets and to ensure operational standards developed by NERC and regional reliability councils are met.

Validation and Verification

Annual performance goals for operational reliability are evaluated against NERC operating standards for the electric utility industry.

Western conducts various internal reviews and audits to validate and verify program performance. Western's program is also subject to continuing independent review by Congress, the Government Accountability Office (GAO), the DOE Office of Inspector General, FERC, the U.S. Environmental Protection Agency, Office of Personnel Management, NERC, and the regional reliability councils.

Program Assessment Rating Tool (PART)

The Department implemented a tool to evaluate selected programs. PART was developed by the Office of Management and Budget (OMB) to provide a standardized way to assess the effectiveness of the Federal Government's portfolio of programs. The structured framework of PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome- and output-oriented goals, the successful completion of which will lead to public benefits, such as increased national security and energy security, and improved environmental conditions. DOE has incorporated feedback from OMB into the FY 2008 Budget Request, and the Department will take the necessary steps to continue to improve performance.

In FY 2004, Western participated in a program assessment with OMB using PART. The resulting scores and findings were provided to Congress with the FY 2004 budget request. Western's scores equated to a "moderately effective" rating attributable to successful planning and management activities on capital investment to upgrade or expand existing infrastructure to promote reliable power delivery. However, these attributes were offset by OMB's contention that Western had neither adequate long-term goals, targets and measures; specifically efficiency measures, nor a unique role in industry and that we compete with private industry. Subsequent changes in energy policy and proposed receipt financing of required annual expenses are removing program constraints which Western feels will allow us to operate in a "fully effective" and business-like manner. Western will continue to work closely with OMB to increase program efficiency as we pursue our statutory mandates with regard to marketing and delivery of Federal power to include customer preference, cost recovery, widespread use of power and revenue disposition.

Major Program Shifts and Changes

- The FY 2008 Budget includes an initiative for all Western Area Power Administration hydroelectric systems to adopt a one-year cost recovery policy for emergency expenses. Beginning in FY 2008, all emergency expenditures Western incurs out of its Emergency Fund for purchase power and wheeling costs will be recovered from ratepayers within one year. This change will assure the Treasury is repaid in a timely manner with minimal deficit impact.

- The Budget continues implementation of a FY 2007 initiative providing that the interest rate for future obligations owed to the Treasury by the Western Area Power Administration for power-related investments be set at the rate Governmental corporations borrow in the market, similar to the interest rates current law sets for Bonneville Power Administration's borrowing from the U.S. Treasury. This new policy will be applied to all power-related investments occurring after September 30, 2006, whose interest rates are not specified in law.

- The Budget does not assume reclassification of receipts from mandatory to discretionary (net zero appropriations) for the annual operating expenses of the Western Area Power Administrations because there was no agreement between the Administration and Congress to reclassify such receipts without legislative action. Nevertheless, the Administration supports this reclassification and will continue to pursue this financing arrangement.

Construction, Rehabilitation, Operation and Maintenance
Western Area Power Administration

Funding by Site by Program

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Western Area Power Administration	572,949	688,511	705,911
Total, Construction, Rehabilitation, Operation and Maintenance	572,949	688,511	705,911

Site Description

Western's service area covers 1.3-million square-miles in 15 States. Western markets and delivers energy to about 750 wholesale power customers. These customers, in turn, provide retail electric service to millions of consumers in these central and western States: Arizona, California, Colorado, Iowa, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah and Wyoming.

Western annually markets and transmits about 10,000 megawatts of power from 56 hydropower plants and sells about 40 percent of regional hydroelectric generation. Western also markets the United States' entitlement from the coal-fired Navajo Generating Station near Page, Arizona.

Western operates and maintains an extensive and complex high-voltage transmission system to deliver power to its customers. Using its 17,005-circuit-mile Federal transmission system, Western will market and deliver reliable electric power to most of the western half of the United States.

The power facilities are made up of 14 multipurpose water resource projects and one transmission project. The systems include Western's transmission facilities and power generation facilities owned and operated primarily by the U.S. Bureau of Reclamation, the U.S. Army Corps of Engineers and the U.S. Section of the International Boundary and Water Commission.

Power sales, transmission operations and engineering services for Western's system are accomplished by its employees at 51 duty stations located throughout its service area. These include the Corporate Services Office in Lakewood, Colorado, and four customer service regional offices in Billings, Montana; Loveland, Colorado; Phoenix, Arizona; and Folsom, California. The Colorado River Storage Project Management Center in Salt Lake City, Utah, also provides customer support.

Falcon and Amistad Operating and Maintenance Fund
Western Area Power Administration

Funding by Site by Program

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Western Area Power Administration	2,665	2,500	2,500
Total, Falcon and Amistad Operating and Maintenance Fund	2,665	2,500	2,500

Site Description

The Falcon-Amistad Project consists of two international dams located on the Rio Grande River between Texas and Mexico. The United States and Mexico operate separate powerplants on each side of the Rio Grande River. The power output is divided evenly between the two Nations. The Department of State's International Boundary and Water Commission (IBWC) owns and operates the U.S. portion of the projects.

Falcon Dam is located about 130 miles upstream from Brownsville, Texas. The United States' portion of construction, operation and maintenance was authorized by Congress in 1950. Construction was started in that year and completed in 1954. The United States' share of Falcon Powerplant capacity is 31.5 megawatts (MW). The powerplant came on line in 1954.

Amistad Dam is located about 300 miles upstream from Falcon Dam. The Amistad Powerplant was constructed by the U.S. Army Corps of Engineers, as agent for the IBWC. The United States' portion of construction, operation and maintenance was authorized by the Mexican-American Treaty Act of 1950. Amistad Dam was completed in 1969. The United States' share of the two generating units, which came on line in 1983, is 66.0 MW.

Project power is marketed to a cooperative in south Texas via Central Power and Light Company's transmission system. There is no Federal transmission associated with these two projects.

Colorado River Basins Power Marketing Fund
Western Area Power Administration

Funding by Site by Program

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Western Area Power Administration	192,281	221,081	232,145
Total, Colorado River Basins Power Marketing Fund	192,281	221,081	232,145

Site Description

The Colorado River Basins Power Marketing Program is comprised of three power systems: the Colorado River Storage Project, including the Dolores and Seedskadee Projects; the Fort Peck Project; and the Colorado River Basin Project. Western Area Power Administration is responsible for construction, maintenance, and operation of facilities for transmitting and marketing the electrical energy generated in these power systems. A brief description of each follows:

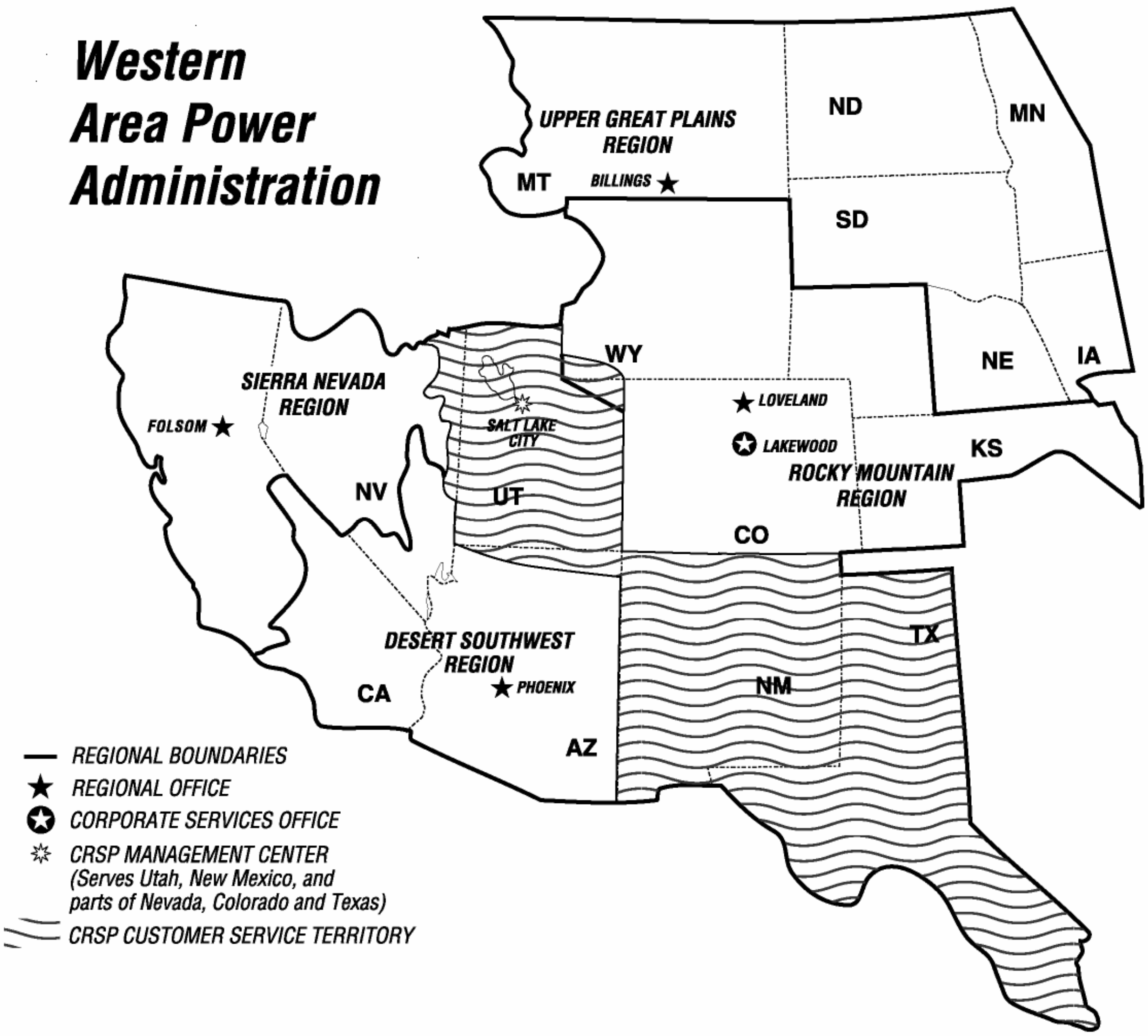
The **Colorado River Storage Project** (CRSP) was authorized in 1956. It consists of four major storage units: Glen Canyon, on the Colorado River in Arizona near the Utah border; Flaming Gorge on the Green River in Utah near the Wyoming border; Navajo on the San Juan River in northwestern New Mexico; and the Wayne N. Aspinall unit on the Gunnison River in west-central Colorado.

CRSP has a combined storage capacity that exceeds 33.5 million acre-feet. Five Federal powerplants associated with the project, with 16 generating units, have an operating capacity of 1,710 MW. CRSP provides for the electrical needs of more than a million people spread across Colorado, Utah, New Mexico and Arizona. Portions of Nevada and Wyoming are also served by CRSP power.

The **Dolores Project**, located in Montezuma and Dolores counties in southwestern Colorado, and the **Seedskadee Project**, located in southwestern Wyoming, were authorized as participating projects of CRSP. Dolores, a multipurpose project, provides 12.8 MW of installed power generating capacity along with municipal and industrial water, irrigation water, and recreation and fish and wildlife enhancement. The Dolores Project powerplants at McPhee Dam and the Towaoc Canal produce 1.3 and 11.5 MW, respectively. Seedskadee's power facilities, associated with the project's Fontenelle Dam, include an 11.5-MW powerplant, switchyard and necessary transmission lines to interconnect with the CRSP transmission system at Flaming Gorge Powerplant.

The **Fort Peck Project**, located on the Missouri River in northeastern Montana, was begun under an Executive Order in October 1933 as part of the Public Works Administration. The Fort Peck Project Act of 1938 authorized the completion, maintenance and operation of the project, and the Flood Control Act of 1944 authorized operational integration of the project with the Pick-Sloan Missouri Basin Program to serve a common market area. Installed generating capacity of the 5 units is 218 MW, which is delivered primarily to customers in eastern Montana and western North Dakota.

The Central Arizona Project (CAP) was authorized as an element of the **Colorado River Basin Project** to furnish irrigation and municipal water supplies to Arizona and New Mexico, and for other purposes. In FY 2007, this project will use reimbursable arrangements; not the revolving fund authorities.


Western
Area Power
Administration
UPPER GREAT PLAINS
REGION
MT
BILLINGS
ND
MN
SD
WY
NE
IA
SIERRA NEVADA
REGION
FOLSOM
SALT LAKE
CITY
LOVELAND
LAKEWOOD
KS
ROCKY MOUNTAIN
REGION
NV
UT
CO
TX
DESERT SOUTHWEST
REGION
PHOENIX
CA
NM
AZ
REGIONAL BOUNDARIES
REGIONAL OFFICE
CORPORATE SERVICES OFFICE
CRSP MANAGEMENT CENTER
(Serves Utah, New Mexico, and
parts of Nevada, Colorado and Texas)
CRSP CUSTOMER SERVICE TERRITORY

Construction, Rehabilitation, Operation and Maintenance

Funding Profile by Subprogram

(dollars in thousands)

	FY 2006 Current Appropriation[a]	FY 2007 Request	FY 2008 Request
Construction, Rehabilitation, Operation and Maintenance Account (CROM)			
Operation and Maintenance (O&M)[b]	47,295	45,734	53,271
Construction and Rehabilitation [c]	53,957	60,205	62,915
Purchase Power and Wheeling (PPW)[d]	321,397	427,931	425,254
Program Direction [e]	143,667	147,748	157,304
Utah Mitigation and Conservation	6,633	6,893	7,167
Total, CROM (Operating Expenses)	572,949	688,511	705,911
Use of Alternative Financing	-58,135	-197,741	-242,242
Offsetting Collections–Colorado River Dam Fund (P.L. 98-381)	-4,162	-3,705	-3,937
Offsetting Collections–PPW (P.L. 108-447, P.L. 109-103)	-279,000	-274,852	-258,702
Total, CROM (Budget Authority)	231,652	212,213	201,030

Public Law Authorizations:
Public Law 57-161, "The Reclamation Act of 1902"
Public Law 78-534, "Flood Control Act of 1944"
Public Law 95-91, "Department of Energy Organization Act" (1977)
Public Law 102-486, "Energy Policy Act of 1992"
Public Law 66-389, "Sundry Civil Appropriations Act" (1922)
Public Law 76-260, "Reclamation Project Act of 1939"
Public Law 80-790, "Emergency Fund Act of 1948"
Public Law 102-575, "Reclamation Projects Authorization and Adjustment Act of 1992"
"Economy Act" of 1932, as amended (41 stat. 613)
"Interior Department Appropriation Act of 1928" (44 stat. 957)
Public Law 70-642, "Boulder Canyon Project Act" (1928)
Public Law 75-756, "Boulder Canyon Project Adjustment Act" (1940)
Public Law 98-381, "Hoover Power Plant Act of 1984"

[a] FY 2006 adjusted to reflect the general 1.00% across-the-board rescission of $2,339,920 (P.L. 109-148).
[b] O&M funding amounts include activities of the Boulder Canyon Project in the amounts of $1,162,000, $746,000, and $929,000 for FY 2006, FY 2007, and FY 2008, respectively. Funding also includes use of alternative financing methods in the amount of $461,000, $1,091,000, and $11,971,000 for FY 2006, FY 2007, and FY 2008, respectively.
[c] Construction and Rehabilitation funding includes use of alternative financing methods in the amount of $540,000, $33,928,000, and $47,915,000 for FY 2006, FY 2007, and FY 2008, respectively.
[d] PPW program includes use of receipts from the recovery of PPW expenses of $279,000,000, $274,852,000, and $258,702,000 in FY 2006, FY 2007, and FY 2008, respectively. In addition, alternative financing methods are included in the amounts of $42,397,000, $153,079,000, and $166,552,000 for FY 2006, FY 2007, and FY 2008, respectively.
[e] Program Direction funding amounts include activities of the Boulder Canyon Project which are funded through Colorado River Dam Fund receipts via a reimbursable agreement with the Department of Interior as authorized in P.L. 98-381. By year, the amounts are $3,000,000, $2,959,000, and $3,008,000 for FY 2006, FY 2007, and FY 2008, respectively. Funding also includes use of alternative financing methods in the amount of $14,737,000, $9,643,000, and $15,804,000 for FY 2006, FY 2007, and FY2008, respectively.

Mission

Western markets and delivers reliable, cost-based Federal hydroelectric power and related services.

Benefits

Western delivers reliable power and related services across a 1.3-million-square-mile area to a diverse group of about 750 customers, including municipalities, cooperatives, public utility and irrigation districts, Federal and State agencies, and Native American tribes. Western's marketing efforts and delivery capability provide for recovery of annual operational costs, including the generating agencies' hydropower related costs, and repayment of taxpayer investment in the Federal hydropower program. Western repays the Federal investment for which it is responsible within the timeframes established by law and regulations.

Operation and Maintenance
Funding Schedule by Activity

(dollars in thousands)

	FY 2006[a]	FY 2007	FY 2008
Operation and Maintenance [b]			
Regular Operation and Maintenance	23,615	24,472	25,138
Replacements and Additions	23,680	21,262	28,133
Subtotal, Operation and Maintenance	47,295	45,734	53,271
Alternative Financing	-461	-1,091	-11,971
Use of Receipts from Colorado River Dam Fund	-1,162	-746	-929
Total, Operation and Maintenance (Budget Authority)	45,672	43,897	40,371

Description

The mission of Western's Operation and Maintenance (O&M) subprogram is to assure continued reliability of the Federal power system by operating and maintaining Western's transmission system at or above industry standards, including replacement of aging equipment and removal of constraints which would impede power flows.

Benefits

Western's operation and maintenance subprogram supports DOE's Strategic Theme 1, Energy Security, by emphasizing replacement and upgrading of existing electrical system infrastructure to sustain reliable power delivery to our customers, to support a stable and reliable interconnected power system, to contain annual maintenance expenses, and to retain the value of our assets. Western ensures reliable electric power in a safe, cost-effective manner, and achieves continuity of service throughout its 15-State service territory by maintaining its power system at or above industry maintenance standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing clean-up activities, and maximizing revenues gained from non-firm energy and transmission sales.

Detailed Justification

(dollars in thousands)

FY 2006	FY 2007	FY 2008

Supplies and materials, such as wood poles, instrument transformers, meters and relays must be procured to provide the necessary resources to respond t routine and emergency situations in Western's high-voltage interconnected transmission system. Western implemented reliability-centered

[a] FY 2006 adjusted to reflect the general 1.0% across-the-board rescission of $461,329 (P.L. 109-148).
[b] Program descriptions and funding amounts include activities of the Boulder Canyon Project. These activities are funded through receipts from the Colorado River Dam Fund via a reimbursable agreement with the Department of Interior as authorized in P.L. 98-381.

maintenance (RCM) scheduling to contain costs. RCM focuses on identifying critical components in a system and uses preventive and predictive maintenance practices to repair or replace equipment as needed. Technical services, such as waste management disposal, environmental impact analyses, and pest and weed control are used as needed.

Western's planned replacements and additions activity is based on an assessment of condition and criticality of equipment, maintenance/frequency of problems for individual items of equipment, availability of replacement parts, safety of the public and Western's personnel, environmental concerns, and an orderly work plan. The work plans, coordinated with Western's power customers, who ultimately bear the burden of all Western expenses, reflect an overall sustainable level of effort, with shifts in emphasis between categories (i.e., electrical versus communication equipment) in any given year.

Electrical equipment replacements, such as circuit breakers, transformers, insulators, revenue meters, switches, control boards, relays and oscillographs must be made to assure reliable service to Western's customers. System component age, availability of spare parts, environmental concerns, and risk to system reliability necessitate orderly replacement before significant problems develop.

Replacement, upgrade and installation of fiber optics, Supervisory Control and Data Acquisition (SCADA) systems, and other communication and control equipment continues to provide increased system reliability and to reduce maintenance and equipment costs.

Capitalized movable equipment, such as special purpose vehicles (e.g., cranes, auger trucks, manlifts), special purpose equipment (e.g., pole trailers, industrial tractors, brush chippers), specialized test equipment (e.g., motion analyzers and relay test equipment), computer-aided engineering equipment, office equipment, and IT equipment and software, must be upgraded and replaced.

Personnel expenses and personnel performance accomplishments associated with the O&M subprogram are combined with those of the Construction and Rehabilitation subprogram and are reflected in the Program Direction subprogram of Western's budget request.

Regular Operation and Maintenance	**23,615**	**24,472**	**25,138**

Supplies and materials necessary to respond to routine and emergency situations in Western's high-voltage interconnected transmission system will be purchased. This includes miscellaneous equipment, and software used for power billing, transmission planning, e-tagging, and energy scheduling, as well as supplies and materials such as wood poles (individual pole replacement; excludes whole line replacements), instrument transformers, meters, relays, etc. necessary to respond to routine and emergency situations in Western's high-voltage interconnected transmission system. The request includes $928,874 for activities in the Boulder Canyon Project, funded directly through receipts from the Colorado River Dam Fund.

The continuing maintenance of Western's transmission system at or above industry standards supports DOE's Strategic Theme 1 by minimizing sudden failure, unplanned outages, and possible regional power system disruptions. Safe working procedures are discussed before work begins to optimize safety for the public, Western's staff, and equipment. The request is based on projected work plans for activities funded from this account. Estimates are based on historical data of actual supplies needed to operate and maintain the transmission system. Costs are based on recent procurement of similar items.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Replacements and Additions	**23,680**	**21,262**	**28,133**

Western's planned replacements and additions activity is based on an assessment of condition and criticality of equipment, maintenance/frequency of problems on individual items of equipment, availability of replacement parts, safety of the public and Western's personnel, environmental concerns, and an orderly work plan. Replacement of aged power system components maximizes the reliability and availability of Western's system by reducing the risk of equipment failure, unplanned outages, and possible regional power system disruptions. Removing environmental hazards and replacement of aged equipment eliminates safety hazards for the public and Western's personnel. Planned activity is detailed by category below.

▪ **Electrical Equipment**	**11,606**	**10,392**	**13,071**

Electrical equipment, such as circuit breakers, transformers, relays, batteries and chargers, reactors, meters, buses, surge arresters, capacitor banks and disconnect switches, will replace obsolete equipment at facilities throughout Western's 15-State area. Also included is test equipment used by maintenance crews, such as metering and relaying test sets, pentimeters, ohm testers, oil dielectric testers, battery load testers, and specialized communication and environmental control test equipment. Replacement and rehabilitation of single wood pole structures, overhead ground wires, and line hardware will extend the life of aging, deteriorating transmission lines. Miscellaneous minor equipment/parts that become a part of are capitalized with other rehabilitation projects and are necessary for crews to maintain 17,005 circuit miles of transmission line and 292 substations.

Costs are based on analysis of system operation/maintenance requirements and concerns, customer-coordinated work plans, actual costs of recent similar projects, and bottom-up budgeting techniques.

▪ **Communications Equipment**	**3,116**	**2,515**	**5,626**

Key to system reliability, replacement of remote terminal units, telephone systems, microwave links, and aged 7 Ghz analog radio systems with digital ratio and fiber optics continues. Manufacturers have discontinued support of the obsolete analog equipment and there is inadequate channel capacity to support our needs. The staged movement to narrow communications band spectrums for UHF radios as directed by the National Telecommunications and Information Administration (NTIA) continues.

Western's communication systems are currently made up of approximately 7 percent fiber optics, 81 percent fixed radio, and 12 percent mobile radio. Western currently has 1,381 radio frequency authorizations for fixed radio bands, of which 586, or 42 percent, are analog. The funding requested here will not be used to replace equipment impacted by the Spectrum Relocation initiative.

In addition, Western will continue upgrades to its existing SCADA systems which control Western's electric power system. These hardware and software upgrades improve grid reliability by allowing the main computer to communicate with remote terminal units in the 292 substations across Western's territory, thus allowing the dispatcher to operate a device in any of these substations to make changes rapidly to respond to power industry requirements or system emergencies.

Costs are based on analysis of system operation/maintenance requirements, customer-coordinated work plans, actual costs of recent similar projects, and bottom-up budgeting techniques.

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
▪ **Spectrum Relocation Equipment**	**0**	**0**	**0**

In December 2004, the Congress passed and the President signed the Commercial Spectrum Enhancement Act (CSEA, Title II of P.L. 108-494), creating the Spectrum Relocation Fund (SRF) to streamline the relocation of Federal systems from certain spectrum bands to accommodate commercial use by facilitating reimbursement to affected agencies of relocation costs. The Federal Communications Commission has auctioned licenses for reallocated Federal spectrum, which will facilitate the provision of Advanced Wireless Services to consumers. Funds are made available to agencies in fiscal year 2007 for relocation of communications systems operating on the affected spectrum. These funds are mandatory and will remain available until expended, and agencies will return to the SRF any amounts received in excess of actual relocation costs.

Western's cost for relocation of 291 frequency assignments is estimated at $108.2 million which will be reimbursed from auction proceeds administered by the Office of Management and Budget. Western plans to accept these funds as an appropriation transfer which will be offset by the costs for relocation. Therefore, no appropriations are being requested for this activity.

	FY 2006	FY 2007	FY 2008
▪ **Capitalized Movable Equipment**	**8,958**	**8,355**	**9,436**

These funds will purchase 7 special purpose line trucks and three specialized trailers. Western's first choice of vehicle coverage is a GSA lease, when such vehicles are available. However, GSA cannot always accommodate our needs, especially in the Upper Great Plains Region and somewhat in the Desert Southwest Region, where vehicles must be equipped for extreme weather conditions that exist. At those times, it is necessary to purchase such vehicles, and this request is representative of that condition. All sedans, vans, SUVs, and light trucks are GSA-leased. Western uses 733 vehicles, 429 (57 percent) of which are leased from GSA. Replacement of government-owned vehicles is based on the Federal Management Regulations guidelines, the same guidelines used by GSA. Specialized equipment such as man lifts, snow cats, forklifts, cranes, front-end loaders, and caterpillars are also included. Delay in replacing such equipment will result in decreased reliability and safety for the maintenance crews.

This funding is for replacement of the N27TK helicopter purchased in 1985 and servicing Western's Upper Great Plains Region. With a fleet of 3, Western has found its helicopter program to be the most cost effective for transmission line patrols due mainly to the wide-open spaces in the West, remote access, and often rugged terrain with the N27TK helicopter. Already exceeding its normal life of 20 years, this purchase, supported by a life-cycle cost analysis, will enable Western to meet performance and safety requirements of its aviation program based on an A-76 Aviation Study. Purchase of this state-of-the-art equipment will provide aviation program efficiencies such as increased level of safety, higher degree of airworthiness, increased payload capability, higher cruise speeds, improved avionics, lower maintenance costs, and expands the potential area of operation. Delay will result in increased maintenance costs and decreased safety and reliability.

Other capitalized movable equipment needed to support the O&M of the interconnected power system include substation test equipment, brush chipper, map board replacement; security equipment such as installation of perimeter intrusion detection devices, card readers and associated

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
software, security cameras and recording devices at various sites throughout Western; Information Technology equipment such as server and router replacements, firewalls, tape storage systems, cyber security upgrades, LAN upgrades, Enterprise application upgrade for Western's maintenance management system (Maximo), computer-aided equipment (CAD) equipment used for engineering-specific applications and drawing archives; global information system hardware upgrades; replacement of equipment for the MiniPower Simulator at Western's Electric Power Training Center to accommodate changes in technology; and helicopter equipment replacements identified during overhaul that add value to the helicopter or extend the service life, such as engine, rotor blades, avionics, airframe, and other major components.			
Delay will result in decreased reliability, safety, and security at substations and other facilities throughout Western. Replacement needs are based on age, reliability, and safety of equipment, customer-coordinated review, cost analysis of rebuild versus replacement, availability of replacement parts, and obsolescence of diagnostic maintenance tools. Costs are determined using actual costs of similar items.			
Total, Operation and Maintenance	**47,295**	**45,734**	**53,271**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Regular Operation and Maintenance	
▪ The overall net increase in regular O&M is attributed to inflation and decreased maintenance costs.	+666
Replacements and Additions	
▪ The increase in replacements and additions of electrical equipment (+$2,679,000) results from inflation and additional electrical equipment replacements such as circuit breakers, transformers, relays, batteries and chargers, reactors, meters, capacitor banks and switches. The increase in communications equipment (+$3,111,000) is primarily caused by the need for a Supervisory Control and Data Acquisition (SCADA) system. Purchase of a helicopter in FY 2008 results in an increase in movable property (+$1,081,000).	+6,871
Total Funding Change, Operation and Maintenance	**+7,537**

Construction and Rehabilitation
Funding Schedule by Activity

(dollars in thousands)

	FY 2006[a]	FY 2007	FY 2008
Construction and Rehabilitation			
Transmission Lines and Terminal Facilities	29,665	33,023	27,274
Substations	15,687	22,122	30,270
Other [b]	8,605	5,060	5,371
Subtotal, Construction & Rehabilitation	53,957	60,205	62,915
Alternative Financing	-540	-33,928	-47,915
Total, Construction & Rehabilitation (Budget Authority)	53,417	26,277	15,000

Description
The mission of Western's Construction and Rehabilitation (C&R) subprogram is to assure continued reliability of the Federal power system by modification, replacement, additions, and interconnections to the Federal power system.

Benefits
Western's C&R subprogram supports DOE's Strategic Theme 1, Energy Security, by emphasizing replacement and upgrading of existing electrical system infrastructure to sustain reliable power delivery to our customers, to support a stable and reliable interconnected power system, to contain annual maintenance expenses, and to retain the value of our assets. Replacement and upgrade of aged power system components are crucial to system reliability, and communications improvements maintain vital control over system operations. Both contribute to attaining or exceeding monthly control compliance ratings established by the North American Electric Reliability Council (NERC) by reducing the risk of equipment failure, unplanned outages, and possible local and regional power system disruptions. Reducing the hazards associated with worn or aging equipment, correcting design deficiencies, and replacing deteriorated wood poles which present a serious climbing hazard to linemen, minimizes Western's exposure to unsafe conditions. In addition, public safety is supported by avoiding or minimizing the negative impacts of unplanned outages and by minimizing the instances of downed lines. C&R subprogram activities support the repayment of Federal power investment by promoting a well-planned C&R program with a relatively stable budget over the long term, by avoiding significant additional costs of emergency "breakdown maintenance," and by preventing outages which could impact power deliveries, purchase power costs, and power revenues.

[a] FY 2006 adjusted to reflect the general 1.0% across-the-board rescission of $539,570 (P.L. 109-148).
[b] Other includes communication equipment, maintenance facilities, power facility developmental costs, and minor unscheduled jobs.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

Western's transmission system has 17,005 circuit-miles of line and 292 substations. Of the 8,016 miles of wood poles, 6,254, or 78 percent, exceed the normal service life of 40 years, with 4,781, or 60 percent, exceeding 50 years. Western is continually testing, treating, and replacing individual wood poles and hardware to delay the need for replacing an entire transmission line. As substation equipment (such as power transformers, circuit breakers, and control equipment) ages, maintenance costs increase, replacement parts become unavailable, risks of outages increase, and system reliability declines. Western has 72 transformers and 86 circuit breakers more than 41 years old. The normal service life for power transformers and power circuit breakers is 40 years and 35 years, respectively. While replacement of this equipment is systematically planned over 10 years, actual replacement varies depending on condition and criticality. All replacement and rehabilitation plans are coordinated with customers to help establish the timing and scope of work at specific substations. When upgrades or additional capacity are required, Western actively pursues opportunities to partner with neighboring utilities to jointly finance activities, which result in realized cost savings and increased efficiencies for all participants.

Western has aggressively reduced its capital investment program from levels around $110 million annually (including Program Direction) in the early 1990s. An estimated base level of $31 million (excluding Program Direction) is required to support a program that emphasizes replacement and upgrade of existing infrastructure to sustain reliable power delivery to our customers while maintaining competitive rates. Western's FY 2008 C&R request of $62.9 million is well above the base level of $31 million because of the backlog due to budget constraints, Congressional earmarks within available funds, FERC orders, and reliability issues resulting from load growth on Western's transmission lines as a result of open access. In recent years, the appropriated funding level for this program has dropped to a level of $12 to $19 million (excluding Program Direction). In FY 2005, Western received appropriations of $13.9 million based on funding needs of $44 million. Of the $13.9 million, Congressional directed funding of $10.1 million left $3.8 million for Western to upgrade its aging infrastructure. In the FY 2004 Performance and Management Assessments Summary of Western's Program Assessment Rating Tool (PART), OMB proposed that Western "modestly increase construction expenditures for scheduled substation equipment replacements and the ongoing replacement of transmission line facilities and housekeeping needs such as a new roof on one of their buildings."

Western continues to refine a long-term C&R program level that will maintain the reliability of, and the Government's investment in, Western's power facilities while minimizing effects on power rates. Our challenge has been to evaluate Western's facilities which were built 40 to 50 years ago, and develop a systematic replacement/upgrade program at a level that retains the value of our assets and assures a safe and reliable transmission system, with minimal rate impacts. OMB's Summary of the PART noted that Western's "system for reviewing and adopting construction projects is rigorous."

Due to the increase in rehabilitation projects and decrease in new construction projects, it is increasingly difficult to plan specific projects years in advance. A piece of equipment scheduled for replacement may test fine two years later at the beginning of the execution year, resulting in deferring that project in favor of replacing equipment at higher risk of failure. Discovery of a failing piece of critical equipment

	FY 2006	FY 2007	FY 2008

(dollars in thousands)

may completely change the planned work priority. Customer needs may also change, causing Western to revise or reprioritize C&R projects. Utilities and other entities are also requesting interconnections to Western's transmission system under the provisions of Western's Open Access Transmission Tariff, adopted in accordance with the spirit and intent of FERC Order No. 888. These projects often surface suddenly and move quickly, and can significantly impact Western's C&R program planning and project priorities. These projects might be advance funded by the customer, in which case there would be no impact on our appropriation request. While this section of our budget request incorporates Western's best efforts to identify and schedule necessary C&R projects, the increased focus on replacements and the realities of operating and maintaining a complex interconnected power system mean unforeseen priority projects will surface from time to time. Western may have to slip or restructure planned projects to accommodate these sudden priority projects, but our C&R program will continue to be focused on replacements and upgrades of aging existing equipment necessary to maintain the reliability and integrity of Western's power transmission system. Western's policy is to continue to assign the highest program priority to those situations that pose the highest risk to safety and system reliability, while meeting the mandates for open access to our transmission system.

Western delays replacement costs for as long as reasonably possible while managing the risk of sudden failure and emergency replacement. Further postponement will contribute to an overall degradation of Western's power facilities, possibly leading to serious power system disruptions and lengthy power outages while crews repair or replace failed equipment under emergency conditions. "Breakdown maintenance" results in higher costs than scheduled replacements and increases safety risks to maintenance crews, as equipment failures are very often tied to extreme weather conditions and/or high system power loadings.

Lead times for equipment delivery are increasing as fewer domestic manufacturers remain in the marketplace, and more equipment must come from foreign sources. Worldwide demand for electrical equipment is also impacting delivery schedules. For major equipment such as transformers, delivery times are averaging 18 months and increasing, making it impossible to procure equipment in the same fiscal year as contract award.

Personnel costs and related expenses for the workforce to plan, collect field data, write specifications, design facilities, award construction contracts, and purchase government-furnished equipment for the C&R activity are combined with those of the O&M activity and are reflected in the Program Direction section of Western's budget request.

For purposes of budget display, the C&R subprogram is broken into three activities: Transmission Lines and Terminal Facilities, Substations, and Other. The Other category includes communications equipment (microwave, fiber optic, and telecommunications), maintenance facilities, power facility development costs, and minor unscheduled jobs. Planned activity is detailed by category below.

Transmission Lines and Terminal Facilities	**29,665**	**33,023**	**27,274**
▪ **Transmission Lines and Terminal Facilities, Continuing Work**	**16,913**	**32,897**	**25,174**
▪ **Congressionally Directed Transmission Line (Topock-Davis-Mead)**	**5,544**	**0**	**0**

(dollars in thousands)		
FY 2006	FY 2007	FY 2008

Continuation of modifications and rehabilitation of the following transmission lines (TL) to ensure power system reliability and stability is planned in FY 2008.

- Relocate and upgrade 13 miles of the Parker-Blythe #1 161-kV TL (Arizona) away from the congested area known as the Parker Strip. Built in 1951, the line has exceeded normal service life, and was scheduled for replacement in 1999. Due to encroachment and safety concerns, replacement of the poles in the Parker Strip area has been cancelled; instead, the TL is to be relocated away from the Parker Strip area, on a new right-of-way, in an area not likely to see development in the area. Western has been unable to prevent encroachment on the existing right-of-way, and the encroachments will only worsen with time, due to the rapid development along this section of the Colorado River. A conductor failure in this area caused substantial damage to several homes. Western was forced to negotiate financial settlements with the afflicted parties due to inadequate language in the right-of-way document. The realignment will greatly reduce safety concerns and increase the maintainability of this TL.
- Relocate and upgrade 13 miles of the Parker-Gila 161-kV TL (Arizona) away from the congested area known as the Parker Strip. Placed in service in 1943, the line has exceeded normal service life, and was scheduled for replacement in 1999. Due to encroachment and safety concerns, replacement of the poles in the Parker Strip area has been cancelled; instead, the TL is to be relocated away from the Parker Strip area, on a new right-of-way, in an area not likely to see development in the area. Western has been unable to prevent encroachment on the existing right-of-way, and the encroachments will only worsen with time, due to the rapid development along this section of the Colorado River due to inadequate language in the right-of-way documents. The realignment will greatly reduce safety concerns and increase the maintainability of this TL.
- The 35-mile Ault-Cheyenne 115-kV TL (Colorado and Wyoming) was constructed in 1939 using wood pole H-frame structures and 250,000 circular mil Anaconda copper conductor. This line is over 60 years old and in need of conductor and hardware replacement. To be spliced, the copper conductor requires special equipment and expertise, and replacement hardware is becoming difficult to find. Although recent testing of the poles on this line section shows the majority of poles are structurally sound, most of these poles have extreme shell rot. Therefore, they are unsafe to climb and line work must be done under clearance using a bucket truck. This safety concern and the fact that the poles are over 60 years old indicate this line section should be rebuilt.
- Rebuild the 146-mile Cheyenne-Miracle Mile 115-kV TL (Wyoming) constructed in 1939 using wood poles with copper conductor. The wood poles are deteriorated and copper conductor has not been used in power lines for many years. Hardware and specialized equipment for splicing and maintaining the copper conductor are no longer available. The poor condition of the line requires excessive maintenance, is subject to outages and requires replacement to maintain reliability in the area.
- Continue Upper Great Plains Region's wood pole life-extension testing and replacement programs on 10 miles of the Leeds-Devils Lake 115-kV TL (North Dakota). This program

	(dollars in thousands)	
FY 2006	FY 2007	FY 2008

maintains wood pole TL, maximizing their effective service lives and delaying the need for expensive total rebuild projects. Without funding, wood pole lines will further deteriorate, increasing the risk of pole and crossarm failures. Line outages caused by these failures could trigger major regional outages given the high loadings now experienced on the interconnected power system.

- The Trinity-Weaverville TL (CA) consists of approximately 9 miles of new 60-kV line from Lewiston to Weaverville and 7 miles of 60-kV rebuilt line from the Trinity Power Plant to Lewiston, with a terminal facility near Weaverville. Consumers in this area routinely have outages, many of which last three to four days in the winter before power can be restored. This project will enhance the reliability of service to Trinity County consumers and fulfill the obligation established by the Trinity Division Act of August 12, 1955, to construct, operate and maintain transmission facilities as may be required to deliver the output of power plants to loads in the County.
- Replace existing Watford City-Williston (North Dakota) 115-kV TL with 230-kV TL. This 42-mile TL has been in service since 1951. The majority of the structures do not meet Western's design criteria. The upgrade of the line will provide additional transfer capability which will alleviate existing reliability criteria violations during system outages.
- Replace existing Casa Grande-Empire (Arizona) 115-kV TL with 230-kV TL using fiber optic ground wire and light-weight steel poles. This 17-mile line was constructed in 1948 using wood H-frame construction. The TL is in poor condition due to aging material and the crossarms, braces, and poles have deteriorated to the point that a failure could occur at any time. Upgrade of this line will increase system reliability and safety and decrease maintenance costs. Adding a new fiber optic path will alleviate a reliability risk as there is currently only one path in place for the fiber optic communications traffic that controls the transmission system's remote relaying, protection, and alarms. Any break in this path shuts down access to this control.

The funding level is determined by estimating the cost to complete each project and breaking out these costs by fiscal year. The estimates are based on recent actual costs to complete similar projects, updated individual project requirements, and past experience.

	FY 2006	FY 2007	FY 2008
▪ **Transmission Lines and Terminal Facilities, Rehabilitation Starts**	**7,208**	**126**	**2,100**

Within target, there is one TL and terminal facility rehabilitation start planned in FY 2008. TL and terminal facility starts address specific system reliability risks or operational problems.

- Rebuild 9.8 miles of existing Gila-Yuma Mesa Tap (Arizona) 34.5-kV TL using existing right of way where feasible. Built in 1943, the wood poles are in need of replacement. Due to the deteriorating condition of these structures, a failure is possible that could result in service interruption, property damage, and injury to the general public or Western's personnel. The existing line was constructed without an overhead ground wire to protect against lightning strikes. Replacement of the existing wood pole line with steel poles and overhead ground wire will increase the safety and reliability of the system.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

Estimates are based on actual costs of recent similar projects, expected costs of needed equipment and services, cost estimating guides, and experience.

	FY 2006	FY 2007	FY 2008
▪ **Transmission Lines and Terminal Facilities, Work Funded by Others**	**0**	**0**	**0**

Potential transmission line and terminal trust work in FY 2008 includes planning, design or construction of:

- Havre-Rainbow 230-kV TL Rebuild with new overhead ground wire and conductors due to generation additions request (Montana).
- Transmission facilities to interconnect the Griffith Transmission Project.
- O'Banion-Elverta Double Circuit 230-kV line for Sacramento Municipal Utility District and the City of Roseville (California).
- Eastern Plains Transmission Project for Tri-State.
- Erie-Hoyt Transmission Line for Tri-State.
- Granby Power Plant -Windy Gap 69-kV TL for Northern Colorado Water Conservancy District (Colorado).

Western's work for others has increased significantly under the open access transmission tariff adopted in response to FERC Order No. 888. The tariff requires Western to provide interconnections to its transmission system. New generation projects typically surface quickly and provide little advance warning for internal planning and budgeting. Western must work with requestors to meet their needs.

Design of these facilities must be closely coordinated with, or accomplished by, Western's design staff to ensure compatibility with Western's equipment and facilities and compliance with applicable electrical and safety codes. These projects also affect transmission system loading and operation. Potential impacts to other system facilities and equipment must be determined since the cost of any necessary modifications must be borne by the interconnection project proponents.

	FY 2006	FY 2007	FY 2008
Substations	**15,687**	**22,122**	**30,270**
▪ **Substations, Continuing Work**	**9,755**	**7,524**	**18,275**

Continue modifications and rehabilitation of the following substations in FY 2008 to ensure power system reliability and stability. The funding level is determined by estimating the cost to complete each project and breaking out these costs by fiscal year. The estimates are based on recent actual costs to complete similar projects, updated individual project requirements, and past experience.

- Replacement and upgrade of equipment at Empire Tap Substation (Arizona). Acquire land and furnish and install a new three circuit breaker, 230-kV ring bus and one new 230/115-kV, 30-MVA transformer. Built in 1953, the tap has remained unchanged and has become a source of operational concern; deteriorating equipment is obsolete, making maintenance difficult and costly. Replacement and upgrade of this equipment is part of the South of Casa Grande Project, which is an upgrade of Western's 115-kV transmission system to 230-kV from Casa Grande Substation to ED 5 Substation to Coolidge Substation, including work at seven substations and

(dollars in thousands)		
FY 2006	FY 2007	FY 2008

approximately 61 miles of transmission line.

- Replacement of Edgeley Substation (North Dakota) transformer KY1A which is a 115/69-kV, 20-MVA auto transformer. KY1A was installed in 1952. Transformer KY1A has exceeded its life expectancy of 40 years. The addition of the equipment for the dedicated transformer bays will add reliability to this substation.

- Upgrade Tracy 230-kV Substation (California) to a double-breaker, double-bus configuration by adding breakers, disconnects, bus, and associated control, protection and communication equipment. This substation design is currently a main and transfer bus configuration. With this configuration, loss of up to six critical 230-kV transmission lines, two major ties to the Tracy 500-kV Substation, and the entire Tracy pumping plant could occur if breaker failure happens due to human error or failure of breaker protection equipment. This would represent a loss of 2,150 MVA of transfer capacity, potentially causing major West Coast power outages during critical load times of the year.

- The terminal facility near Weaverville Substation (California) will include two 60-kV breakers, four disconnect switches, a 20-ft by 30-ft control room, fiber optic cable for the system protection, and a switchyard to connect the Trinity Public Utility District's 60-kV system at Weaverville and Douglas City Substations. This project will enhance the reliability of service to Trinity PUD consumers through a direct interconnection with the CVP transmission grid and provide Trinity the electrical energy authorized by the Trinity Division Act of August 12, 1955.

- Trinity Substation (California) consists of four 230-kV breakers, a connection to the 230-kV line, two 3-phase 230/60-kV transformers, three 60-kV breakers and three 21-kV re-closers with associated relay and control panels. This substation will enhance the reliability of the Trinity Power Plant and service to Trinity Public Utility District's consumers through a 21-kV direct interconnection with the CVP transmission grid.

- Construct a 230-kV terminal at Ault Substation (Colorado) for the Ault-Snowy Range-Miracle Mile 230-kV line. The Cheyenne-Miracle Mile 115-kV Line is planned to be rebuilt with a 230-kV line and the Ault-Cheyenne 115-kV Line is planned to be rebuilt with a 115/230-kV line. A 230-kV termination and 230/115-kV transformation will be required at the Ault Substation.

- Miracle Mile 230-kV Substation (Wyoming) additions in conjunction with the Cheyenne-Miracle Mile transmission line rebuild from 115-kV lines to 230-kV lines. A 230-kV termination and 230/115-kV transformation will be required at the Miracle Mile Substation.

- Construct a 230-kV terminal and a 230/115-kV, 150-MVA transformer at the Snowy Range Substation (Wyoming) for the Ault-Snowy Range-Miracle Mile 230-kV TL. The Cheyenne-Miracle Mile 115-kV TL is planned to be rebuilt with a 230-kV line and the Ault-Cheyenne 115-kV Line is planned to be rebuilt with a 115/230-kV line by Fiscal Year 2009. A 230-kV termination and 230/115-kV transformation will be required at the Snowy Range Substation.

- Construct a 230-kV three breaker switchyard and install a 230/115-kV, 150 MVA transformer at Cheyenne Substation (Wyoming) for the Ault-Snowy Range-Miracle Mile 230-kV line. A 230-kV switchyard and 230/115-kV transformation is required at the Cheyenne Substation to provide

	(dollars in thousands)	
FY 2006	FY 2007	FY 2008

needed voltage support to the area near Cheyenne which has historically had low system voltages. In the near future, the voltages can no longer be mitigated by the use of transformer voltage taps at area substations. System stability in the southeastern portion of Wyoming will be vulnerable to system voltage collapse if the low voltages are not addressed. The planned rebuild of the Cheyenne-Miracle Mile and Ault-Cheyenne 115-kV Lines to 230-kV provide the opportunity to address the low voltages by connecting a 230-kV source to Cheyenne.

- Construct a 230-kV three breaker switchyard and install a 230/115-kV 200 MVA transformer at Beaver Creek Substation (Colorado). In 2005, Western initiated planning for a project to rebuild Western's Beaver Creek-Hoyt 115-kV TL in order to uprate the line by rebuilding it as a 230-kV rated line. Without uprating this line, Western would be forced to lower the total transfer capability of the constrained path TOT3 (WECC Path 36) by about 500 MW. Lowering TOT3 would have drastically impacted the ability of Western and the other owners of TOT3 capacity to transfer generation from Wyoming to load in Colorado.

	FY 2006	FY 2007	FY 2008
▪ **Substations, Rehabilitation Starts**	**5,932**	**14,598**	**11,995**

Within target, eight substation rehabilitation starts are planned in FY 2008:

- Replacement of Brookings Substation (South Dakota) transformer KY1A which is a 110/69/12.5-kV, 18.75-MVA auto transformer. KY1A was installed in 1954. Transformer KY1A has met its life expectancy and should be replaced before catastrophic failure causes degradation to the power system and customer outages. The existing 115-kV main and transfer bus will also be converted to a breaker and a half scheme. The city of Brookings has two lines at 115-kV serving their loads. Because of the existing bus design, both lines are lost in the event of a bus differential trip. Converting to a breaker and a half design will mitigate this situation.

- Upgrade of ED5 Tap Substation (Arizona) with a new five circuit breaker ring bus is a replacement to the existing tap. Constructed in 1952, the existing motor-operated disconnects have not been upgraded, are deteriorating, and are a reliability concern. They are not capable of interrupting load or fault current, making maintenance difficult and costly. Spare parts are obsolete and difficult to replace.

- Upgrade of the Fargo Substation (North Dakota) consists of replacing transformers KV1A and KV2A which are 100 MVA 230/115-kV transformers. The new units will be two 250 MVA 230/115-kv three-phase transformers. Associated transfer bay equipment and materials including circuit breakers, bus, and disconnect switches will be replaced to handle additional capacity and increased fault currents. Based on recent load studies, the existing Fargo 230/115kV transformer banks are not adequately sized to allow for operating with one parallel bank out of service during peak loading conditions.

- Transformer replacement at Grand Island Substation (Nebraska) consists of the addition of one 345/230kv 250MVA transformer bank to be operated in parallel with two existing 345/230kV 250 MVA transformer banks. The addition of two 20 MVAR reactor banks, associated breaker bays, and protection/control equipment would also be required. The existing 345/230-kV transformer banks were placed in service in 1970. They are not adequately sized to allow for operating with one parallel bank out of service during peak loading conditions. Also under a breaker failure condition, the remaining transformer has the potential to load well above its emergency rating.

(dollars in thousands)

- Replacement of old and failing equipment at Gila Substation (Arizona). This 34.5-kV yard was placed in service in 1945 as part of the Parker Dam Project. The circuit breakers and switches are obsolete with no replacement parts available. Failure of this unreliable equipment will prevent Western from serving its customer loads and meeting contractual obligations. This project will replace six 34.5-kV circuit breakers and 18 disconnect switches, as well as reconfigure the station service transformer feed.
- Additions at the Lusk Rural Substation (Wyoming) include transformer relaying, fiber optical cable from Lusk to Podolak Substation and SCADA remote terminal units at Podolak. Lusk was originally constructed by the Bureau of Reclamation in the 1950's. Lusk transformer KX1A (69/24.9 kV) is only protected by high side fuses. High temperature, low oil, and sudden pressure devices on this transformer can neither alarm nor trip any high side interrupting device. In addition, the transformer and 24.9 kV loads are subject to single phasing any time a single high-side fuse blows. Single phasing subjects customer equipment to 50 percent of normal voltage on two phases and severe voltage/phase unbalance to any three phase loads. Since there is no SCADA, this condition may persist until reported by end use customers. This equipment will provide adequate communication and provide more reliable service.
- Replacement of 161-kV oil breakers at Parker Substation (California). Nine of the 161-kV breakers are of the mid-1970's vintage and are oil filled. This project will improve the system reliability, reduce outage times taken for maintenance, reduce operating costs, and eliminate environmental hazards.
- Construct a new 500-kV O'Banion Substation (California) with 500/230-kV transformation. Loop the existing PG&E's Table Mountain – Tesla 500-kV line into the new 500-kV yard. Add breaker bays and associated protection and control circuits to the existing O'Banion 230-kV yard as required. This project will provide the reliability of the CVP transmission system according to NERC/WECC reliability criteria and meet Western's transmission service obligations and will avoid uncontrolled system-wide outages and loss of load which will have a definite impact on local and regional system/economy.

The funding level is determined by estimating the cost to complete each project and breaking out these costs by fiscal year. The estimates are based on recent actual costs to complete similar projects, updated individual project requirements, and past experience.

	FY 2006	FY 2007	FY 2008
▪ **Substations, Work Funded by Others**	**0**	**0**	**0**

Substation trust work in FY 2007 includes:

- Havre Substation 230-kV Bay Addition (Montana).
- Construction of a substation on Bismarck-Heskett 230-kV TL for a new interconnection with Capital Electric (North Dakota).
- Airport Substation 115-kV expansion for City of Redding (California).

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

- Rainbow & Great Falls Substations modifications (Montana).
- Arizona Public Service interconnection to Flagstaff 345-kV Substation (Arizona).

	FY 2006	FY 2007	FY 2008
Other	**8,605**	**5,060**	**5,371**
▪ **Communications Systems**	**6,244**	**3,165**	**3,664**

Each project cost is determined using the actual costs of recent similar projects, estimated quantities of needed materials, past contract costs, specialized cost estimating guides, and in-house experience.

- Continue to replace/modernize/expand communication systems (microwave, fiber optic, global information system, and telecommunication) in the Central Valley Project and the Pick-Sloan Missouri Basin Program to operate and control the transmission system. Replacement parts for existing obsolete communications systems are difficult to obtain and the increased use of remote control of facilities, coupled with the need for greater integration of the Federal system with the rest of the grid and technological advances in the communications field, make secure and reliable communications crucial to Western's mission. Rapid advances in technology and manufacturers' phase-out of support for existing systems drive the need for communications replacements and upgrades. Effective control of remote facilities is crucial to the operation of the power system. Western's communication systems are made up of approximately 7 percent fiber optics, 81 percent fixed radio, and 12 percent mobile radio. Western currently has 1,381 radio frequency authorizations for fixed radio bands, of which 586 or 42 percent are analog. The equipment requested here will not be replaced during the Spectrum Relocation initiative. Sections 1211, 1222(a), 1222(b), 1222(c).

	FY 2006	FY 2007	FY 2008
▪ **Miscellaneous**	**2,361**	**1,895**	**1,707**

- Upgrade facilities to provide additional storage for vehicles, electrical equipment, and supplies that are presently being stored outside, subjected to adverse weather conditions at Western's Dawson maintenance facility (Montana). Ongoing replacement of maintenance building built in 1952 in Montana to provide facilities for housing motorized and movable equipment along with storage and shop areas and crew quarters. Eight crew members are located at this duty station. Current conditions foster increased safety hazards, diminished security, increased outage response times, and decreased work efficiency for this crew. Lack of storage exposes equipment to severe weather conditions.

- Construction of maintenance building at Watertown (South Dakota) to provide facilities for housing motorized and movable equipment along with storage and shop areas. Delay in replacing condemned facility increases safety hazards, weakens security, and exposes equipment to severe weather conditions.

- In addition, these funds would repair a one-mile access road to Nevada substation; roadway has been washed out numerous times and maintenance crews cannot access substation until debris is cleared, creating a reliability and security concern as well as hazardous safety conditions.

- This request includes funding for the demolition and environmental cleanup of a substation in Arizona that has been taken out of service. Delay could result in accidental soil contamination from oil, asbestos air pollution or lead poisoning.

	FY 2006	FY 2007	FY 2008
(dollars in thousands)			

- Continue development of Rocky Mountain Region's Geographical Information System (GIS) mapping system for the Region's electrical transmission system and facilities. Mapping includes transmission lines, access roads, environmental sites, structure locations, substation sites, communication sites, and other important features on the Region's electrical system.

- Annual power facility development costs and miscellaneous minor construction jobs that are not normally scheduled in advance or anticipated as part of larger projects.

	FY 2006	FY 2007	FY 2008
Preconstruction Activities	**0**	**0**	**0**

The following projects will have active preconstruction activities during FY 2008: Replace 9.2 miles of 15-kV Empire-ED5 TL with fiber optic ground wire on light-weight steel poles using existing right-of-way (Arizona); reconductoring of Headgate Rock-Blythe TL (Arizona/California).

	FY 2006	FY 2007	FY 2008
Total, Construction and Rehabilitation	**53,957**	**60,205**	**62,915**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Transmission Lines and Terminal Facilities	
▪ The decrease in Transmission Lines and Terminal Facilities is due primarily to the planned completion of the transmission line phase of the Cheyenne-Miracle Mile Project. The requested funding will allow Western to repair, rebuild, or relocate structures that have been identified as having potential reliability safety, and maintenance problems. It will allow Western to continue its wood pole testing treatment, and replacement programs to maximize service life and postpone costs	-5,749
Substations	
▪ This increase is due primarily to (1) The start of the new 500-kV O'Banion Substation in California to enable Western to support the area transmission needs without compromising reliability and security of the interconnected transmission system. Further delay could result in catastrophic failure causing degradation to power system, decreased reliability, excessive maintenance, safety concerns, and customer outages. (2) The Substation rebuild phase of the Cheyenne-Miracle Mile Project, including Ault, Cheyenne, Miracle Mile, and Snowy Range Substations.	+8,148
Other	
▪ Funding needs for Other capital expenditures such as Communications Systems, Buildings and Roads remain unchanged.	+311
Total Funding Change, Construction and Rehabilitation	**+2,710**

OBN0005C, O'Banion 500-kV Transmission Line and Transformation Station, O'Banion, California

1. Significant Changes

Initial submittal.

2. Design, Construction, and D&D Schedule

(fiscal quarter)

	Preliminary Design start	Final Design Complete	Physical Construction Start	Physical Construction Complete	D&D Offsetting Facilities Start	D&D Offsetting Facilities Complete
FY2008	2Q FY2008	2Q FY2011	3Q FY2011	2Q FY2013	NA	NA

3. Baseline and Validation Status

(dollars in thousands)

	TEC	OPC, except D&D Costs	Offsetting D&D Costs	Total Project Costs	Validated Performance Baseline	Preliminary Estimate
FY 2008	150,000	0	0	150,000		150,000

No baseline has been established. No Other Project Costs (OPC) since all costs are required to be within project costs by FERC accounting methods. No construction funds will be used until the Performance Baseline has been established (4Q FY2009) and validated.

4. Project Description, Justification, and Scope

Project description: New transmission lines, system interconnections and/or upgrades of existing transmission facilities in the Sacramento, CA area to assure the reliability of electricity supplies.

Justification: The project addresses a gap in the reliability of electricity supplies in the Sacramento, CA area hindered by capacity limitations on Western's existing 230-kV transmission lines. The reliability is already compromised as evidenced by the recent use of load shedding to balance supply and demand. The electricity supplies are becoming more unreliable as existing facilities are strained to meet demand in a region that is expected to grow annually by 2.7 percent until 2030 and beyond.

Scope: Requirements to be determined at CD-1.

The project will be conducted in accordance with the project management requirements in DOE Order 413.3A and DOE Manual 413.3-1, Program and Project Management for the Acquisition of Capital Assets.

Compliance with Project Management Order

- Critical Decision – 0: Approve Mission Need – FY2006 (4/13/06 complete)
- Critical Decision – 1: Approve Preliminary Baseline Range – 3Q FY 2008
- External Independent Review Final Report – 3Q FY 2009
- Critical Decision – 2: Approve Performance Baseline – 4Q FY 2009
- Critical Decision – 3: Approve Start of Construction – 3Q FY 2011
- Critical Decision – 4: Approve Start of Operations – 2Q FY 2013

5. Financial Schedule (dollars in thousands)

	Appropriations	Obligations	Costs
Design/Construction by Fiscal Year			
Design			
2008	5,000		
2009	8,000		
2010	3,000		
2011	2,000		
Total, Design	18,000		
Construction			
2010	27,000*		
2011	38,000		
2012	40,000		
2013	27,000		
Total, Construction	132,000		
Total TEC	150,000		

*Note: Value for long lead procurement – to be determined during planning. Funds are only being requested for construction to begin in FY 2010. Design funding was NOT appropriated separately.

6. Details of Project Cost Estimate

Total Estimated Costs

(dollars in thousands)

Cost Element	Current Estimate ($000)	Previous Estimate ($000)
Preliminary and Final Design	18,000	NA
Construction Phase	132,000	

Cost Element	(dollars in thousands) Current Estimate ($000)	Previous Estimate ($000)
Site Preparation		NA
Equipment		NA
All other construction		NA
Contingency		NA
Total, Construction	132,000	NA
Total, TEC	150,000	NA

Other Project Costs

Cost Element	(dollars in thousands) Current Estimate ($000)	Previous Estimate ($000)
Conceptual Planning	NA	NA
Start-up	NA	NA
Offsetting D&D	NA	NA
D&D for removal of the offsetting facility	NA	NA
Other D&D to comply with “one-for-one” requirements	NA	NA
D&D contingency	NA	NA
Total, D&D	NA	NA
Contingency for OPC other than D&D	NA	NA
Total, OPC	NA	NA

7. Schedule of Project Costs

(dollars in thousands)

	Prior Years	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	Outyears	Total
TEC(Design)	0,000	0,000	5,000	8,000	3,000	2,000	0,000	18,000
TEC (Construction)	0,000	0,000	0,000	0,000	27,000	38,000	67,000	132,000
OPC Other than D&D	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
Offsetting D&D Costs	0,000	0,000	0,000	0,000	0,000	0,000	0,000	0,000
Total, Project Costs	0,000	0,000	5,000	8,000	30,000	40,000	67,000	150,000

8. Related Operations and Maintenance Funding requirements

Start of Operation (fiscal quarter)	2Q2013
Expected Useful Life (number of years)	35-50
Expected Future start of D&D for new construction (fiscal quarter)	NA

(Related Funding requirements)

(dollars in thousands)

	Annual Costs		Life cycle costs	
	Current estimate	Prior Estimate	Current estimate	Prior Estimate
Operations	0,000	0,000	0,000	0,000
Maintenance	0,000	0,000	0,000	0,000
Total Related funding	0,000	0,000	0,000	0,000

9. Required D&D Information

Western plans to upgrade existing transmission facilities to increase the transfer capability in the area. D&D is not applicable and FERC accounting methods are required for utility capital investments.

Name(s) and site location(s) of existing facility(s) to be replaced: NA

D&D Information Being Requested	Square Feet
Area of new construction	NA
Area of existing facility(ies) being replaced	NA
Area of any additional space that will require D&D to meet the "one-for-one" requirement	NA

Western's transmission facilities are not offices, nor buildings, but transmission lines and substations.

10. Acquisition Approach (formerly Method of Performance)

Design expected to be by Western staff. Acquisition has not yet been planned. Construction is anticipated to be by competitive procedures.

Purchase Power and Wheeling
Funding Schedule by Activity

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Purchase Power and Wheeling			
Central Valley Project	119,410	219,846	238,671
Pick-Sloan Missouri Basin and Other Programs	201,987	208,085	186,583
Subtotal, Purchase Power and Wheeling (Gross)	321,397	427,931	425,254
Use of Alternative Financing	-42,397	-153,079	-166,552
Subtotal, Purchase Power and Wheeling	279,000	274,852	258,702
Offsetting Collections Realized	-279,000	-274,852	-258,702
Total, Purchase Power and Wheeling (Budget Authority)	0	0	0

Description

The mission of the Purchase Power and Wheeling (PPW) subprogram is to support Western's long-term firm power sale contractual agreements, including wheeling over non-Federal transmission lines as necessary to deliver the firm hydropower resource to customers.

Benefits

The PPW subprogram supports Western's mission to market and deliver reliable, cost-based hydroelectric power and related services. These services are marketed at rates sufficient to recover expenses and Federal investment as established by law. To maximize the marketability of Western's products, Western has entered into long-term contracts with customers of the Central Valley Project (CVP), the Pick-Sloan Missouri Basin Program, as well as other projects, to deliver power based on the normal (average over the long-term) amount of power and/or capacity available from each of the power systems. By its nature, hydropower is a variable resource; it is affected by reservoir storage, drought conditions, powerplant maintenance and other project purposes. Variations occur between load and generation hour-by-hour or even minute-by-minute. Western buys power and related transmission services to fulfill its firm power-sale contractual commitments. Western also buys transmission services, as needed, to provide the benefits of the Federal hydropower resource to numerous Federal, State, municipal, and other preference customers not directly connected to Western's system. Contracting for transmission services encourages the widespread use principle of the Flood Control Act of 1944 and avoids unnecessary Federal duplication of available transmission resources. The acquisition of non-Federal power and transmission services meets Western's power marketing contract provisions which place binding responsibilities on Western to provide firm power to customers of the Pick-Sloan Missouri Basin Program-Eastern Division, Loveland Area Projects and Parker-Davis Project.

The FY 2008 request provides for continuation of PPW receipt funded activities at the estimated level necessary to meet contractual firming needs. No appropriated budget authority is necessary. The request for receipt authority reflects current drought conditions affecting the Pick-Sloan Missouri River Basin, and the elevated market pressures for purchase power across Western's service territory.

The following table illustrates the PPW program assumptions and includes actual FY 2005 amounts.

Purchase Power and Wheeling Program Assumptions

	FY 2005 Actual	FY 2006 Enacted	FY 2007 Request	FY 2008 Request
Power Purchases (gigawatthours)				
Central Valley Project	3,940	1,962	3,610	3,115
Pick-Sloan Missouri Basin and Other Programs	4,873	4,414	4,899	3,400
Total, Purchases	8,813	6,376	8,509	6,515
Purchase Power Prices ($/megawatthour)				
Central Valley Project	38.8	48.0	50.6	64.4
Pick-Sloan Missouri Basin and Other Programs	43.6	43.0	39.9	49.3
Cost of Power Purchases ($000)				
Central Valley Project	152,799	94,175	182,765	200,532
Pick-Sloan Missouri Basin and Other Programs	212,291	189,795	195,703	167,701
Total, Purchase Power Costs	365,090	283,970	378,468	368,233
Wheeling Costs ($000)				
Central Valley Project	19,841	25,235	37,081	38,139
Pick-Sloan Missouri Basin and Other Programs	9,552	12,192	12,382	18,882
Total, Wheeling Costs	29,393	37,427	49,463	57,021
Total, Purchase Power and Wheeling	394,483	321,397	427,931	425,254

Detailed Justification

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Central Valley Project	**77,013**	**91,214**	**102,947**

No appropriations are requested. This is authority to use offsetting collections only.

▪ **Central Valley Project, Program Requirement**	**119,410**	**219,846**	**238,671**

In FY 2008, Western continues to deliver on its contractual power commitments to customers under the Post 2004 Marketing Plan. The budget request assumes current full load service customers will continue to choose service from Western through “Custom Product” contractual arrangements. Western also purchases power to support variable resource customers on a pass-thru basis. If project net generation is not sufficient, Western may also purchase to support project use load, First Preference Customer load, and sub-control area reserve requirements.

Hydro conditions have improved for the CVP; the FY 2008 request anticipates a reduction in

	FY 2006	FY 2007	FY 2008

(dollars in thousands)

purchases of 14 percent from the FY 2007 level. However, the FY 2008 funding requirement is increasing due to higher purchase power prices anticipated in FY 2008; up 28 percent from the FY 2007 estimate of $50.6/MWh. The FY 2008 forecast of $64.4/MWh is a conservative estimated based on actual FY 2006 costs which averaged $80/MWh at mid-year.

	FY 2006	FY 2007	FY 2008
▪ **Central Valley Project, Alternative/Customer Financing**	**-42,397**	**-128,632**	**-135,724**

Contractual arrangements have been made with customers providing opportunities for alternative financing of the purchase power requirements. Alternative financing methods include net billing, bill crediting, and direct customer funding.

	FY 2006	FY 2007	FY 2008
Pick-Sloan Missouri Basin and Other Programs	**201,987**	**183,638**	**155,755**

No appropriations are requested. This is authority to use offsetting collections only.

	FY 2006	FY 2007	FY 2008
▪ **Pick-Sloan Missouri Basin and Other Programs, Program Requirement**	**201,987**	**208,085**	**186,583**

In FY 2008, the request continues to support long-term firm power commitments to customers of the Eastern and Western divisions of the Pick-Sloan Missouri Basin Program, the Fryingpan-Arkansas Project, and the Parker-Davis Project commensurate with the levels of average firm hydroelectric energy marketed by Western. The request also provides transmission support for the Pacific Northwest-Southwest Intertie Project. The total program estimates shown for FY 2008 are based primarily on market pricing of short-term firm energy, negotiated transmission rates, and Western and generating agency' forecasts reflecting the impact of existing drought conditions on purchase requirements. The FY 2008 program level is down from the FY 2007 estimate due to an anticipated softening of the severe drought conditions experienced over the last several years. The reduction of 30 percent in purchases however, is offset moderately by a 23 percent increase in the average purchase prices based on current FY 2006 actual at $49 per MWh. Wheeling costs are increased in FY 2008 reflecting current FY 2006 costs.

	FY 2006	FY 2007	FY 2008
▪ **Pick-Sloan Missouri Basin and Other Programs, Alternative/Customer Financing**	**0**	**-24,447**	**-30,828**

Alternative financing methods negotiated with customers will be used where effective to provide an offset to the total program receipt financing requirement.

	FY 2006	FY 2007	FY 2008
Total, Purchase Power and Wheeling	**279,000**	**274,852**	**258,702**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Central Valley Project	
▪ The gross PPW requirement of $238.7 million in FY 2008 is up $18.8 million from the $219.8 million level anticipated in FY 2007. As a result of improved water conditions, purchase power levels are expected to drop to 3,115 GWhs, at a cost of $200.5 million in FY 2008; compared to 3,610 GWhs at a cost of $182.8 million in FY 2007. The average purchase price, based on current conditions, is up from $50.6/MWh budgeted in FY 2007 to $64.4/MWh in FY 2008; a 28 percent increase. Western expects an inflationary increase in transmission costs; at $38.1 million, FY 2008 is up slightly from the $37.1 million estimated for FY 2007. Note: The PPW amounts are for offsetting collection authority and alternative financing; no direct appropriations are necessary.	+18,825
Pick-Sloan Missouri Basin and Other Programs	
▪ The gross PPW requirement of $186.6 million in FY 2008 is dropping by $21.5 million from the $208.1 million FY 2007 level. The decrease reflects an anticipated softening of the long-term drought conditions. As a result, purchase power requirements have decreased from 4,899 GWhs in FY 2007 to 3,400 GWhs in FY 2008. Offsetting the drop however, average purchase power prices are increased in FY 2008 based on current FY 2006 market conditions; FY 2008 at $49/MWh is up 24 percent from the $40/MWh budgeted for FY 2007. Wheeling costs estimated at $18.9 million are up from $12.4 million anticipated in FY 2007 based on FY 2006 costs. Note: The PPW amounts are for offsetting collection authority and alternative financing; no direct appropriations are requested for this activity.	-21,502
Total Funding Change, Purchase Power and Wheeling	**-2,677**

Program Direction

Funding Profile by Category

	(dollars in thousands)		
	FY 2006[a]	FY 2007	FY 2008
Program Direction [b]			
Salaries & Benefits	98,715	104,894	109,213
Travel	7,203	8,150	8,327
Support Services	20,866	20,458	20,429
Other Related Services	16,883	14,246	19,335
Subtotal, Program Direction	143,667	147,748	157,304
Less Use of Alternative Financing	-14,737	-9,643	-15,804
Use of Receipts from Colorado River Dam Fund	-3,000	-2,959	-3,008
Total, Program Direction (Budget Authority)	125,930	135,146	138,492
Full-time Equivalents	1,085	1,060	1,081

Mission

Western's Program Direction subprogram provides compensation and all related expenses for the workforce that operates and maintains Western's high-voltage interconnected transmission system and associated facilities; those that plan, design, and supervise the construction of replacements, upgrades and additions (capital investments) to the transmission facilities; and those that market the power and energy produced to repay annual expenses and capital investment

The Program Direction subprogram supports DOE's Energy Security Strategic Theme, Goal 1.3, Energy Infrastructure. To attain reliability performance, dispatchers match generation to load minute-by-minute to meet or exceed performance levels established by NERC. Western maintains the interconnected system at or above industry standards to reduce transmission outages. Energy schedulers maximize revenues from non-firm energy sales and power rates are reviewed and adjusted to support repayment of Federal investment. Western trains its employees on a continuing basis in occupational safety and health regulations, policies and procedures, and conducts safety meetings at employee, supervisory and management levels to keep the safety culture strong. Accidents are reviewed to ensure lessons are learned and proper work protocol is in place.

The Program Direction subprogram further supports Western's Human Capital Management (HCM) Workforce Plan. HCM Workforce Plan activities include: exploring ways to increase HR efficiency through consolidation; the development and/or expansion of intern/apprenticeship programs in the occupations of energy marketing, dispatcher, lineman, and electrician; introduction of an under-study program in Power Marketing, prior to an incumbent retiring; rotational training programs for engineers; strategic use of knowledge sharing and training events in critical occupations; and, succession planning

[a] FY 2006 reflects the general 1.0 percent across-the-board rescission of $1,272,020 (P.L. 109-148).
[b] Program descriptions and funding amounts include activities of the Boulder Canyon Project. These activities are funded through a Reimbursable Agreement with the Department of the Interior, Bureau of Reclamation.

development programs for mid- to upper-level graded Federal positions. By design, costs for these HCM programs will be minimal as local area expertise and facilities will be used to the maximum extent possible. The HCM Workforce Plan noted that no new A-76 studies were required and/or anticipated at this time.

Western operates and maintains a transmission system to deliver reliable electric power in a clean and environmentally-safe, cost-effective manner within its 15-State service territory. Western achieves continuity of service by maintaining its power system at or above industry standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing environmental clean-up activities, and maximizing the benefits gained from non-firm energy sales. Additionally, Western operates the Western Electricity Coordinating Council's Rocky Mountain/Desert Southwest Reliability Coordination Center.

In concert with its customers, Western reviews required replacements and upgrades to its existing infrastructure to sustain reliable power delivery to its customers and to contain annual maintenance expenses. The timing and scope of these replacements and upgrades are critical to assure that Western's facilities do not become the "weak link" in the interconnected system. Western pursues opportunities to join with neighboring utilities to jointly finance activities, which avoid redundant facilities and result in realized cost savings and/or increased efficiencies for all participants.

Detailed Justification

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Salaries and Benefits	**98,715**	**104,894**	**109,213**

Salaries and benefits are provided for Federal employees to operate and maintain, on a continuing basis, Western's high-voltage interconnected transmission system comprised of 17,005 circuit-miles of line, 292 substations, associated power system control and communication, and general plant facilities. Craft workers rapidly restore the transmission system following any disturbance, and routinely maintain and/or replace equipment to assure capability for reliable delivery of power. Dispatchers provide 24-hour-a-day operation of four dispatching centers and one reliability coordination center. Dispatchers respond to minute-by-minute changes to load and generation to meet or exceed NERC and industry averages for system reliability and performance. Engineers and craft workers maintain the interconnected system at or above industry standards to reduce transmission outages. Energy schedulers maximize revenues from non-firm energy sales. Staff provides continuing services such as system operations, power billing and collection, power marketing, rate setting, energy services, environmental, safety, security and emergency management. Due to the extreme hazards associated with a high-voltage electrical system, staff makes safety a priority in each and every task. Staff inspects construction activities in progress (identified in the Construction and Rehabilitation activity) to ensure quality results and safe working methods. General power resources planning and preconstruction activities continue, including planning, environmental clearance, collection of field data, design of facilities, and issuance of specifications for future rehabilitation and upgrades of existing transmission lines and the review/coordination of requests for transmission system interconnections. Staff evaluates general power resources, collaborating and planning with customers and other members of the interconnected transmission system, to identify the most effective transmission system improvements to maximize benefits to all participants.

Total FTE numbers for FY 2008 include 1,081 for Western's Construction, Rehabilitation, Operation

	FY 2006	FY 2007	FY 2008

(dollars in thousands)

and Maintenance (CROM) Account activities. Included in this amount are 17 FTE for Boulder Canyon Project (BCP) activities accomplished using receipts from the Colorado River Dam Fund under a reimbursable agreement with the Bureau of Reclamation. FTE reflected for CROM Account activities total 1,069 and 1,042 for FY 2006 and 2007, respectively. FTE associated with BCP activities total 16 for FY 2006 and 18 FY 2007. The additional within target FTE reflected in FY 2008 for Western's CROM Account includes a shift in 10 FTE from Western's Colorado River Basins Power Marketing Fund. The shifting of FTEs supports the increase of Western's O&M program. The additional changes within target FTEs are required for positions to support various functions within Western. Examples of these positions include a Public Utility Specialist to assist in power billing due to the change in market design, an Energy Management and Marketing Specialist to assist in load scheduling and settlement disputes; a Computer Specialist for increased security workload on power marketing systems and system operations; Electrical Engineers for IT SCADA support; an Operation and Transmission Advisor to supervise dispute resolution and settlement functions, and develop business practices; Journeyman Meter and Relay Technicians; a Market Analyst to assist in optimizing Western's merchant functions; and other support positions.

The FY 2008 funding request reflects anticipated salary and within-grade increases to fund the majority of the FTE financed in this account. The program request includes approximately $1,926 thousand for salary and benefit activities of the Boulder Canyon Project, and other financing methods funds the remainder. Western's overall average budgeted salary/benefit costs per FTE for FY 2007 and FY 2008 are $99,000 and $101,030 respectively. More than 37 percent of Western's personnel salaries and compensation are determined through wage surveys and union negotiations (craft workers, power system dispatchers, schedulers, and marketers) and become effective at the beginning of a fiscal year rather than in January as do the General Schedule increases.

Travel	**7,203**	**8,150**	**8,327**

Estimates, including $162,000 for the Boulder Canyon Project, include transportation and per diem allowances for day-to-day performance of duties of Federal staff, including crews who maintain the interconnected system. The remote and rural locations in Western's 15-State service area result in less competitive pricing. Rental/lease of GSA vehicles and other transportation estimates are also included. Estimates are based on historical costs and an assessment of planned activity. The increase is attributable to escalating airfare and lodging costs, partially offset by a decrease to the indirect costs distributed to this activity.

Support Services	**20,866**	**20,458**	**20,429**

Support services funded in this category include information processing, warehousing, job related training and education, engineering, miscellaneous advisory and assistance services, and general administrative support. The Boulder Canyon portion of the support services estimate totals $408,000. The decrease to this activity is primarily due to removal of the Architect and Engineering Services request, as defined by OMB A-11. The budget for this workscope is currently requested within the Other Related Expenses category of this budget submission. This decrease is partially offset by inflationary increases and a budget request for job related training and education within this category.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Other Related Expenses	**16,883**	**14,246**	**19,335**

Other related expenses include rental space, utilities, supplies and materials, telecommunications, personal computers, printing and reproduction, training tuition, and DOE's working capital fund distribution. The Boulder Canyon portion of these expenses total $512,000. Rental space costs assume the General Services Administration's (GSA) inflation factor. Other costs are based on historical usage and actual cost of similar items. The increase is predominantly due to the change in funding category of Architect and Engineering (A&E) Services from support services to this category, as well as an increase in workscope within those services. This increase includes: services associated with evaluating and designing roadway repair of Western's most critical and important sites; testing and certification of a clean-up site to meet EPA regulations prior to releasing the property to GSA for disposal; environmental studies due to cultural sensitivity and tortoise habitat issues prior to the realignment of transmission lines necessitated because of reliability and safety issues; and, A&E services associated with a transmission line upgrade which is a new project on an Indian reservation. Also included in this request is an increase attributable to purchases from other government accounts, for activities such as background investigations and design work on the Market Redesign Technology Upgrade. These increases are offset by a decrease to job related training which is now identified within the support services category.

Total, Program Direction	**143,667**	**147,748**	**157,304**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Salaries and Benefits	
▪ The increase to salary and benefits includes anticipated salary increases to fund the FTE financed in this account, to include those salaries determined through negotiations.	+4,319
Travel	
▪ The increase to travel is attributable to escalating airfare and lodging costs, partially offset by a decrease to the indirect costs distributed to this activity.	+177
Support Services	
▪ Support services estimate includes an increase to job related training in recognition of an increased emphasis in budgeting for this activity, and is supported by actual costs in prior years. This increase also reflects critical support for Western's Human Capital Workforce Plan such as Western's Leadership Development Program. This increase is offset by a decrease to Architect and Engineering Services which has been redefined by OMB as a non-support service and is now budgeted for under Other Related Expenses.	-29

	FY 2008 vs. FY 2007 ($000)
Other Related Expenses	
▪ Other Related Services increase is predominantly due to the change in funding category of Architect and Engineering (A&E) Services from support services to this category, as well as an increase in workscope within those services. This increase includes: services associated with evaluating and designing roadway repair of Western's most critical and important sites; testing and certification of a clean-up site to meet EPA regulations prior to releasing the property to GSA for disposal; environmental studies due to cultural sensitivity and tortoise habitat issues prior to the realignment of transmission lines necessitated because of reliability and safety issues; and, A&E services associated with a transmission line upgrade which is a new project on an Indian reservation. Also included in this request is an increase attributable to purchases from other government accounts, for activities such as background investigations and design work on the Market Redesign Technology Upgrade. These increases are offset by a decrease to job related training which is now identified within the support services category.	+5,089
Total Funding Change, Program Direction	**+9,556**

Support Services by Category

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Technical Support			
Economic and Environmental Analysis	4,012	1,372	1,498
Test and Evaluation Studies	0	0	0
Total, Technical Support	4,012	1,372	1,498
Management Support			
Management Studies	0	0	0
Training and Education	0	0	906
Automated Data Processing	5,762	4,979	5,909
Reports and Analyses Management and General Administrative Services	11,092	14,107	12,116
Total, Management Support	16,854	19,086	18,931
Total, Support Services	20,866	20,458	20,429

Other Related Expenses by Category

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Training	650	650	294
Working Capital Fund	752	759	735
Printing and Reproduction	183	126	135
Rental Space	1,965	2,033	2,016

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Software Procurement/Maintenance Activities/			
Capital Acquisitions	4,510	3,171	2,899
Purchases from Government Accounts	900	1,023	1,553
Architectural and Engineering Services	0	0	2,998
Other Services	7,923	6,484	8,705
Total, Other Related Expenses	16,883	14,246	19,335

Utah Mitigation and Conservation

Funding Schedule by Activity

	(dollars in thousands)		
	FY 2006[a]	FY 2007	FY 2008
Utah Mitigation and Conservation	6,633	6,893	7,167
Total, Utah Mitigation and Conservation (Budget Authority)	6,633	6,893	7,167

Description

The Reclamation Projects Authorization and Adjustment Act of 1992, Title IV, established the Utah Reclamation Mitigation and Conservation Account (Account) in the Treasury of the United States. The purpose of this Account is to ensure that the level of environmental protection, mitigation, and enhancement achieved in connection with projects identified in the Act and elsewhere in the Colorado River Storage Project in the State of Utah is preserved and maintained. The Administrator of Western is authorized to deposit funds into the Account. Such expenditures are to be considered non-reimbursable and non-returnable. The Utah Reclamation Mitigation and Conservation Commission established under Title III of the Act, is authorized to administer all funds deposited into this Account.

Benefits

This Account provides for the preservation of fish and wildlife and recreation resources impacted by the Central Utah Project and the Colorado River Storage Project in the State of Utah.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Utah Mitigation and Conservation	**6,633**	**6,893**	**7,167**
A deposit of $7,167 thousand will be made to this Account.			
Total, Utah Mitigation and Conservation	**6,633**	**6,893**	**7,167**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Utah Mitigation and Conservation	
▪ This increase is based on the required calculation using factors found in the Economic Assumptions, CPI – Urban Customers.	+274
Total Funding Change, Utah Mitigation and Conservation	**+274**

[a] FY 2006 reflects the general 1.0 percent across-the-board rescission of $67,000 (P.L. 109-148).

Falcon and Amistad Operating and Maintenance Fund

Funding Profile by Subprogram

(dollars in thousands)

	FY 2006 Current Appropriation[a]	FY 2007 Request	FY 2008 Request
Falcon and Amistad Operating and Maintenance Fund	2,665	2,500	2,500
Total, Falcon and Amistad Operating and Maintenance Fund (Budget Authority)	2,665	2,500	2,500

Public Law Authorizations:
Public Law 103-236, "Foreign Relations Authorization Act, Fiscal Years 1994 and 1995"
The Act of June 18, 1954 (68 Stat. 255)

Mission

The Falcon and Amistad Operating and Maintenance Fund (Maintenance Fund) was established in the Treasury of the United States as directed by the Foreign Relations Authorization Act, Fiscal Years 1994 and 1995. The Maintenance Fund is administered by the Administrator of Western for use by the Commissioner of the U.S. Section of the International Boundary and Water Commission (IBWC) to defray administrative, O&M, replacements, and emergency costs for the hydroelectric facilities at the Falcon and Amistad Dams.

Benefits

The Falcon-Amistad Project hydroelectric power generation plants sell generated power to rural electric cooperatives through Western. The United States' share of the generating capacity of the two powerplants is 97.5 MW. All revenues collected in connection with the disposition of electric power generated at the Falcon and Amistad Dams, except monies received from the Government of Mexico, are credited to the Maintenance Fund. Any monies received from the Government of Mexico are credited to the General Fund of the U.S. Treasury. Revenues collected in excess of expenses are used to repay, with interest, the cost of replacements and original investments, thus supporting Western's Program Goal. Full funding will support 24-hour/day operation and maintenance of the two powerplants to ensure response to ever-changing water conditions, customer demand, and continual coordination with operating personnel of the Government of Mexico. In addition, power will be marketed, repayment studies will be completed, and revenues collected. The Federal staff funded under this program continues to be allocated to the U.S. Section of IBWC by the Department of State.

[a] FY 2006 reflects the general 1.0 percent across-the-board rescission of $26,920 (P.L. 109-148).

Falcon and Amistad Operating and Maintenance Fund
Funding Schedule by Activity

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Falcon and Amistad Operating and Maintenance Fund			
Salaries and Benefits	1,745	1,754	1,785
Routine Services	766	622	596
Miscellaneous Expenses	145	108	104
Marketing, Contracts, Repayment Studies	9	16	15
Total, Falcon and Amistad Operating and Maintenance Fund	2,665	2,500	2,500

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Salaries and Benefits	**1,745**	**1,754**	**1,785**

Salaries and benefits are provided for 34 positions of the U.S. Section of the IBWC who operate and maintain the two powerplants on a 24-hour/day basis, including planned maintenance activities, required safety services, and emergency response to flood operations and/or equipment failure. The slight increase is attributed to promotions, salary, and cost of living adjustments.

Routine Services	**766**	**622**	**596**

Routine services such as inspection and service of the HVAC and air compressor systems, fire suppression systems, elevators, self-contained breathing apparatus, recharge and hydro-testing of fire extinguishers, calibration of test equipment, rebuild of electric motors, and repair of obsolete equipment when replacement parts are no longer available, will be provided. Additionally, replacement of tools and equipment, security and intrusion detector systems. The request includes $200,000 to complete the fiber optic communication upgrade project installation, which includes installing a fiber optic line from the Power Plant to the Project Office and interconnect other buildings such as the Warehouse, Hydro Office and Water Treatment Plant Building. Additionally, the request includes $150,000 to implement a Supervisory Control and Data Acquisition (SCADA) System within the power plant. Some of the benefits anticipated from implementing this system include: improving generating efficiencies; reducing operating, overtime, and maintenance costs; increase safety of personnel and equipment; monitoring capabilities; and, provide accurate data acquisition and report generation.

Miscellaneous Expenses	**145**	**108**	**104**

Estimates include miscellaneous expenses for IBWC employees and technical advisors, including travel, training, communications, utilities and printing. Planned training and travel activities include that which is essential for flood response, dam safety, power house safety, to comply with the standards of the Interagency Commission on Dam Safety (ICODS), Occupational Safety and Health Administration (OSHA), the National Dam Safety Act, and to participate in the international efforts of drought management. The decrease in this activity is attributed to a decrease to transportation and travel estimates.

	FY 2006	FY 2007	FY 2008
	(dollars in thousands)		
Marketing, Contracts, Repayment Studies	**9**	**16**	**15**

Costs for marketing power, administration of power contracts, and preparation of rate and repayment studies are included. Based on accurate studies, staff ensures that power revenues are set at an appropriate level to recover annual expenses and meet repayment schedules.

Total, Falcon and Amistad Operating and Maintenance Fund Budget Authority	**2,665**	**2,500**	**2,500**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Salaries and Benefits	
▪ The slight increase is attributed to promotions, salary, and cost of living adjustments.	+31
Routine Services	
▪ The decrease in routine services reflects a slightly lower level of equipment and tool replacements	-26
Miscellaneous Expenses	
▪ The decrease in this activity is attributed to a decrease in transportation and travel estimate	-4
Marketing, Contracts, Repayment Studies	
▪ The decrease is attributable a decrease in indirect costs charged to this account.	-1
Total Funding Change, Falcon and Amistad Operating and Maintenance Fund	**0**

Colorado River Basins Power Marketing Fund

Funding Profile by Subprogram

(dollars in thousands)

	FY 2006 Current Appropriation[a]	FY 2007 Request	FY 2008 Request
Colorado River Basins Power Marketing Fund			
Equipment, Contracts and Related Expenses	152,245	180,347	190,444
Program Direction	40,036	40,734	41,701
Total, Operating Expenses from new authority	192,281	221,081	232,145
Offsetting Collections Realized	-192,281	-244,081	-255,145
Total, Obligational Authority	0	-23,000	-23,000

Public Law Authorizations:
Public Law 75-529, "The Fort Peck Project Act of 1938"
Public Law 84-484, "The Colorado River Storage Project Act of 1956"
Public Law 90-537, "The Colorado River Basin Project Act of 1968"
Public Law 95-91, "Department of Energy Organization Act" (1977)

Mission

Western operates and maintains the transmission system for the projects funded in this account to ensure an adequate supply of reliable electric power in a clean and environmentally safe, cost-effective manner. The Colorado River Basins Power Marketing Program (Program) is comprised of the three power systems: the Colorado River Storage Project, including the Dolores and Seedskadee Projects; the Fort Peck Project, and the Colorado River Basin Project. This program is funded through Western's business-type revolving fund (Federal Enterprise Fund), the Colorado River Basins Power Marketing Fund.

Benefits

Western achieves continuity of service by maintaining its power systems at or above industry standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing clean-up activities, and maximizing the revenues gained from non-firm energy sales. In concert with its customers, Western reviews required replacements to its existing infrastructure to sustain reliable power delivery to its customers and to contain annual maintenance expenses.

Revenues from the sale of electric energy, capacity and transmission services replenish the fund and are available for expenditure for operation, maintenance, replacements, power billing and collection, program direction, purchase power and wheeling, interest, emergencies, and other power marketing expenses. Power sales and other revenues, which are collected in excess of expenses, are used to repay

[a] FY 2006 reflects the general 1.0 percent across-the-board rescission of $26,920 (P.L. 109-148).

Federal investments to the U.S. Treasury. This request represents Western's estimate of obligations to finance these business-type operations.

Equipment, Contracts and Related Expenses

Funding Schedule by Activity

(dollars in thousands)

	FY 2006	FY 2007	FY 2008
Equipment, Contracts and Related Expenses			
Supplies, Materials, and Services	9,219	11,739	10,148
Purchase Power Costs	118,325	154,250	163,213
Capitalized Equipment	13,873	6,360	6,421
Interest/Transfers	10,828	7,998	10,662
Total, Equipment, Contracts and Related Expenses	152,245	180,347	190,444

Description

This program supports the Department of Energy's Strategic Theme, Goal 1.3, Energy Infrastructure. Western ensures an adequate supply of reliable electric power in a safe, cost-effective manner, and achieves continuity of service throughout its service territory by maintaining its power system at or above industry standards, rapidly restoring service following any system disturbance, mitigating adverse environmental impacts, performing clean-up activities, and maximizing the revenues gained from ancillary services and cost-based non-firm energy sales.

Benefit

Western's equipment, contracts and related expenses are necessary to operate and maintain this activity. Revenues from the sale of electric energy, capacity and transmission services replenish the fund and are available for expenditure for operation, maintenance, power billing and collection, program direction, purchase power and wheeling, interest, emergencies, and other power marketing expenses.

Supplies and materials, such as wood poles, instrument transformers, meters and relays, must be procured to provide necessary resources to respond to routine and emergency situations in the high-voltage interconnected transmission system. Technical services, such as waste management disposal and pest/weed control, are used as needed.

Western's planned replacement and addition activity is based on an assessment of age and the maintenance frequency/problems of individual items of equipment, availability of replacement parts, safety of the public and Western's personnel, environmental concerns, and an orderly work plan. The work plans, coordinated with Western's customers who ultimately bear the burden of all Western expenses, reflect an overall sustainable level of effort, with shifts in emphasis between categories (i.e. electrical versus communication equipment) in any given year.

Electrical equipment replacements, such as circuit breakers, transformers, insulators, revenue meters, switches, control boards, relay and controls must be acquired to assure reliable service to Western's customers. System age and environmental concerns necessitate orderly replacement before significant problems develop.

Replacement and upgrade of microwave, SCADA, and other communication and control equipment continues to provide increased system reliability, and reduce maintenance and equipment costs.

Capitalized movable equipment such as special purpose vehicles (e.g., truck tractor, diggers), special purpose equipment (e.g., pole trailers, brush chippers), specialized test equipment (e.g., motion analyzers and relay test equipment), computer-aided engineering equipment, office equipment, IT equipment and software must be upgraded and replaced.

Electrical resources and transmission capability to firm up the Federal hydropower supplies needed to meet Western's contractual obligations will continue to be obtained. Transmission wheeling services are also purchased when a third party's transmission lines are needed to deliver Federal power to Western's customers.

Reimbursements to the U.S. Army Corps of Engineers for operation and maintenance of the Fort Peck Powerplant and planned interest payments to the U.S. Treasury are also included in this section.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Supplies , Materials, and Services	**9,219**	**11,739**	**10,148**

Supplies, materials, and services necessary to respond to routine and emergency situations in the high-voltage interconnected transmission system will be procured, and reimbursements to the U.S. Army Corps of Engineers for operation and maintenance of the Fort Peck Powerplant will continue. A well-maintained transmission system supports Western's attainment of reliability and transmission availability performance by preventing sudden failure, unplanned outages, and possible regional power system disruptions. By providing 24-hour/day reliable electric power delivery to its customers, Western secures revenues for repayment of the Federal investment. Safe working procedures are discussed before work begins to optimize public safety, Western personnel, and equipment. The target request is based on projected work plans for activities funded from this Account. Estimates are based on historical data of actual supplies needed to maintain the transmission system reliably, including emergency situations such as ice storms and tornadoes. Costs are based on recent procurement of similar items. The decrease is primarily due to a slight decreased requirement in this activity.

Purchase Power Costs	**118,325**	**154,250**	**163,213**

Electrical resources, transmission capability and wheeling services will be purchased. The request anticipates the continued low-steady-flow tests conducted at Glen Canyon Dam, as required by the Glen Canyon Dam Environmental Impact Statement Record of Decision. Additionally, amounts include obligational authority to accommodate replacement power purchases for customers served by the Colorado River Storage Project. The replacement power purchases, a provision of the Salt Lake City Area Integrated Projects electric power contracts, are made at the request of power customers at times Western lacks sufficient generation to meet its full contract commitment. The funds for the replacement power purchases are advanced by the requestors prior to the purchase. Anticipated purchase power budget estimates increase in FY 2008 as a result of increased power costs to Western, and an increase in delivered MWh.

Capitalized Equipment	**13,873**	**6,360**	**6,421**

Capitalized equipment including circuit breakers, transformers, relays, switches, transmission line equipment, microwave, SCADA, and other communication and control equipment, will be acquired to assure reliable service to Western's customers. Replacement and upgrade of aged power system components are crucial to system reliability and transmission availability performance. Removing

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

environmental hazards and replacing aged equipment eliminates safety hazards for the public and Western's personnel. Planned communications equipment purchases remain relatively constant and include funding for the continuation of the project to replace analog microwave with fiber optic ground wire and fiber optic terminal. Also being replaced is aged communication buildings as the fiberglass constructed buildings have suffered extensive irreparable physical damage. Transmission line estimates include the purchase of poles, crossarms, conductors, overhead ground wire and hardware for the continued transmission line rebuilds and replacement to the 230-kV specifications of the Harvre-Rainbow line, as the current microwave system is obsolete.

Planned substation estimates include funding to upgrade the programmable logic controllers at the Pinnacle Peak Substation, and the continuation of the program to upgrade circuit switches as they are aged and worn. Also included is the replacement of air core reactors at Hayden, and reactor and breaker replacement at Shelby. Western is beginning the fourth year of a 10-year program to replace older electro-mechanical relays with microprocessor relays due to aged equipment. The microprocessor relays will assist in finding faults faster in order to more efficiently restore service to the customer. Also planned is the replacement of existing transformer monitors with Digital Temperature and Dissolved Gas monitors. This new technology enhances reliability of critical equipment. Funding is also requested to replace circuit breakers at Shiprock, Midway, and Blue Mesa, replace aged disconnect switches, and install security improvements per NERC guidelines at substation facilities. Other miscellaneous items required for substation replacements include surge arrestors, batteries and chargers, and monitoring equipment.

Planned movable capitalized property estimates include the replacement of special purpose trucks at Havre and Ft. Peck. The existing trucks have reached the end of their useful life and require major transmission rebuilds. Also requested is a new loader to clear the right-of-ways under an agreement with the Forest Service. Other estimates include the replacement of outdated test equipment, and test equipment to troubleshoot the new digital microwave radio system. Replacement is also planned for aging information technology support systems and router. The dependability of this equipment is nearing the uncertainty mark and reaching vendor end of life. Other requests include funding for the continuation SCADA Upgrade program as well as other small minor enhancements that provide for the ease of maintenance, protection of equipment and materials, and environmental compliance.

Interest/Transfers	**10,828**	**7,998**	**10,662**

Interest payments to the U.S. Treasury will occur. Estimates are based on Power Repayment Studies for the Projects funded in this account. The projected interest payment increases in FY 2008 primarily due to an increase in investment and a reduction in principal payments made from the prior years estimated Power Repayment Study.

Total, Equipment, Contracts and Related Expenses	**152,245**	**180,347**	**190,444**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Supplies, Materials, and Services	
▪ The decrease is attributable to a lower level of purchases.	-1,591
Purchase Power Costs	
▪ Purchase power costs increase in FY 2008 as a result of an increase in the costs of purchase power and the delivery of additional MWh.	+8,963
Capitalized Equipment	
▪ The decrease in capitalized equipment purchases is primarily attributed to a decreased level of purchases associated with planned replacement of substation equipment offset by a slight increase in replacement of transmission line hardware.	+61
Interest/Transfers	
▪ Planned interest payment to the U.S. Treasury in FY 2008 increases due to increase in investment and a reduction in principal payments made from the prior years estimated Power Repayment Study.	+2,664
Total Funding Change, Equipment, Contracts and Related Expenses	**+10,097**

Program Direction

Funding Profile by Category

	FY 2006	FY 2007	FY 2008
	(dollars in thousands)		
Program Direction			
Salaries and Benefits	29,017	29,974	29,913
Travel	2,013	2,121	2,182
Support Services	4,592	4,874	5,196
Other Related Expenses	4,414	3,765	4,410
Total, Program Direction	40,036	40,734	41,701
Full Time Equivalents	264	271	261

Mission

Program Direction provides the Federal staffing resources and associated costs required to provide overall direction and execution of the Colorado River Basins Power Marketing Fund. Western trains its employees on a continuing basis in occupational safety and health regulations, policies and procedures, and conducts safety meetings at employee, supervisory and management levels to keep the safety culture strong. Accidents are reviewed to ensure lessons are learned and proper work protocol is in place.

Detailed Justification

	FY 2006	FY 2007	FY 2008
	(dollars in thousands)		
Salaries and Benefits	**29,017**	**29,974**	**29,913**

Salaries and benefits will be provided for Federal employees who operate and maintain the Program’s high-voltage integrated transmission system and associated facilities; plan, design, and supervise the replacement (capital investments) to the transmission facilities; and market the power and energy produced to repay annual expenses and capital investment. Engineers and craft workers rapidly restore the transmission system, comprised of approximately 4,000 circuit-miles of transmission lines and associated substations, switchyards, communication, control and general plant facilities, following any disturbance. Staff routinely maintain and/or replace equipment to assure capability for reliable power delivery. Dispatchers respond to minute-by-minute changes to load and generation to meet or exceed the NERC and industry averages. Energy schedulers maximize revenues from non-firm energy sales, and power rates are reviewed and adjusted, thereby supporting the repayment of Federal investment. Staff provides continuing services such as system operations, power billing and collection, power marketing, energy services, technology transfer, environmental, safety, security and emergency management activities. Due to the extreme hazards associated with a high-voltage electrical system, staff makes safety a priority in each and every task. Staff evaluates general power resources, collaborating and planning with customers and members of the interconnected transmission system to identify the most effective transmission system improvements to maximize benefits to all participants.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

The 261 FTE supported in this account reflects both direct and indirect (portions of administrative and general expense employees). Amounts are based on planned work associated with facilities funded through this Account and not on specific positions; therefore, FTE numbers may vary from year to year. The funding increase reflects anticipated salary and within-grade increases, slightly offset by a decrease in FTE. As authorized in P.L. 99-141, Western annually establishes pay rates and compensation policy for some employees (craft workers, power system dispatchers, schedulers, and marketers) based on prevailing rates in the electric utility industry. Due to recruitment/retention issues for those occupations across the Nation and increased staff in these categories to meet the additional workload requirements attributed to FERC Order Nos. 888 and 889, Western's Federal salary/benefit costs for the dispatching/scheduling functions increase at varying rates.

	FY 2006	FY 2007	FY 2008
Travel	**2,013**	**2,121**	**2,182**

Transportation/per diem allowances for day-to-day performance of duties of Federal staff, including crews maintaining the transmission facilities will continue. Rental/lease of GSA vehicles and transportation of things are also included. Estimates are based on historical travel costs, adjusted for inflation and planned activity. Increased levels are attributable to inflation and an increased cost of transportation, slightly offset by a decrease in Western's indirect travel distribution charged to this account.

	FY 2006	FY 2007	FY 2008
Support Services	**4,592**	**4,874**	**5,196**

Support services funded in this category include IT support, warehousing, computer-aided drafting/engineering, and general administrative support. The increase is primarily attributed to inflationary factors, an increase in ADP requirements, and an increased emphasis on budgeting for mission related training in support of Western's Human Capital Management Workforce Plan.

	FY 2006	FY 2007	FY 2008
Other Related Expenses	**4,414**	**3,765**	**4,410**

Other related expenses include, but are not limited to, DOE's working capital fund distribution, space, utilities and miscellaneous charges, printing and reproduction, training tuition, maintenance of office equipment, supplies and materials, telecommunications, personal computers, and multi-project costs. Intermittent specialized services, not included in on-going support service contracts, are also included. Rental space costs assume the GSA inflation factor. Other costs are based on historical usage and actual cost of similar items. The request reflects inflationary increases and increases to supplies and materials, miscellaneous services, utility costs, and software acquisitions.

	FY 2006	FY 2007	FY 2008
Total, Program Direction	**40,036**	**40,734**	**41,701**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Salaries and Benefits	
▪ Decrease in salaries and benefits is attributed to the reduction in FTE charged to this account, offset by an increase salary and within grade increases, including salaries determined by prevailing rates in the electric utility industry.	-61

Travel

- Increased levels are attributable to inflationary factors, and an increase in transportation and travel costs. +61

Support Services

- The increase is primarily attributed to inflationary factors, an increase in ADP requirements, and an increase in mission related training. +322

Other Related Expenses

- The request reflects inflationary increases and increases to supplies and materials, miscellaneous services, utility costs, and software acquisitions. +645

Total Funding Change, Program Direction **+967**

Support Services by Category

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Technical Support			
Economic and Environmental Analysis	0	0	0
Test and Evaluation Studies	0	0	0
Total, Technical Support	0	0	0
Management Support			
Management Studies	0	0	0
Training and Education	0	0	152
ADP Support	1,985	1,022	1,259
Administrative Support	2,607	3,852	3,785
Total, Management Support	4,592	4,874	5,196
Total, Support Services	4,592	4,874	5,196

Other Related Expenses by Category

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Training	200	200	91
Working Capital Fund	172	201	185
Printing and Reproduction	44	30	29
Rental Space	692	721	689
Software Procurement/Maintenance Activities/Capital Acquisitions	982	711	401
Other Services	2,324	1,902	3,015
Total, Other Related Expenses	4,414	3,765	4,410

System Statistics

	FY 2006	FY 2007	FY 2008
Generating Plants (Number)	56	56	56
Generating Capacity:			
Installed Capability (kW)	10,293,000	10,293,000	10,293,000
Substations [a]:			
Number [b]	292	295	297
Capacity (kVa) [c]	25,672,680	25,702,680	25,702,680
Transmission Lines (Circuit-miles)[d]:			
500-kV	628.30	628.30	628.30
345-kV	1,574.03	1,574.03	1,574.03
230-kV	6,968.31	6,968.31	6,993.31
161-kV	888.52	888.52	888.52
138-kV	330.19	330.19	330.19
115-kV	5,670.28	5,670.28	5,671.98
69-kV and below	945.96	954.46	970.96
Total circuit-miles	17,005.59	17,014.09	17,057.29

[a] Number of substations in out years is based on facilities that are projected to be commissioned or ownership transferred in that year.
[b] Additions planned for FY 2007 include Empire Substation (AZ), Hilken Substation (ND) and Trinity Substation (CA). Additions planned for FY 2008 include Snowy Range Substation (WY) and Zorb Substation (AZ).
[c] FY 2007 includes an increase of 30,000 kVA at Trinity Substation (CA).
[d] Addition planned for FY 2007 is Welton-Mohawk (AZ), 34.5 kV, 8.5 miles; additions planned for FY 2008 are Trinity-Weaverville (CA), 60 kV, 16.5 miles; San Louis-Rio Colorado (AZ), 230 kV, 25 miles; and Animas-LaPlata 115 kV, 1.7 miles.

Estimate of Gross Revenues [a]

(dollars in thousands)

	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Boulder Canyon Project	69,374	80,947	86,861	86,510	86,794	86,022	84,353
Central Valley Project [b]	165,149	310,525	330,517	340,000	349,647	360,273	376,383
Central Arizona Project [c]	102,342	102,342	102,342	102,342	102,342	102,342	102,342
Falcon-Amistad Project	5,115	4,897	4,897	4,896	4,895	4,894	4,893
Fryingpan-Arkansas Project	15,482	15,963	15,421	15,329	15,213	14,423	14,423
Pacific Northwest-Southwest Intertie Project	29,751	32,409	34,123	32,656	32,656	32,656	32,656
Parker-Davis Project	47,002	45,225	45,221	45,701	46,085	46,473	45,204
Pick-Sloan Missouri Basin Program	317,867	357,867	358,671	372,236	372,535	372,556	372,921
Provo River Project	250	258	261	264	277	276	276
Washoe Project	598	598	598	598	598	598	598
Salt Lake City Area Integrated Projects	167,701	172,480	174,810	176,109	177,343	177,489	177,699
Subtotal, Gross Revenues	920,631	1,123,511	1,153,722	1,176,641	1,188,385	1,198,002	1,211,748
Agency Rate Proposal [d]		0	30	171	265	415	604
Total, Gross Revenues	920,631	1,123,511	1,153,752	1,176,812	1,188,650	1,198,417	1,212,352

[a] For most power systems, amounts are based on the FY 2005 Power Repayment Studies (PRS). The Central Arizona Project (CAP) does not have a PRS because it has no power repayment obligation; amounts shown are based on estimated projections.
[b] FY 2006 sales estimates for the Central Valley Project assumed power delivery at reduced levels pending establishment of outyear project use and negotiation of customer Custom Product contractual requirements.
[c] Western has contractually agreed for the Salt River Project (SRP) to act as the scheduling entity and operating agent for CAP's portion of the Navajo Generating Station's output (547 MW). In return, as Western retains marketing responsibility, SRP agreed to pay monthly costs to cover annual expenses.
[d] The Budget provides that the interest rate for future obligations owed to the Treasury by Western Area Power Administration for power-related investments be set at the rate Governmental corporations borrow in the market, similar to the interest rates current law sets for Bonneville Power Administration's borrowing from the U.S. Treasury. This new policy will be applied to all power-related investments occurring after September 30, 2006 whose interest rates are not specified in law.

Estimate of Energy Sales[a]

(in gigawatthours) [b]

	FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Boulder Canyon Project	4,090	4,063	4,015	4,072	4,047	4,069	4,076
Central Valley Project [c]	5,447	8,116	7,621	7,777	7,941	8,113	8,293
Central Arizona Project (Navajo)	4,273	4,273	4,273	4,273	4,273	4,273	4,273
Falcon-Amistad Project	79	79	79	79	79	79	79
Loveland Area Projects [d]	2,123	2,123	2,123	2,123	2,123	2,123	2,123
Pacific Northwest-Southwest Intertie Project [e]	0	0	0	0	0	0	0
Parker-Davis Project	1,346	1,346	1,346	1,346	1,346	1,346	1,346
Pick-Sloan Missouri Basin Program, Eastern Division	8,991	9,582	10,031	10,437	10,447	10,466	10,477
Provo River Project	17	17	17	17	17	17	17
Washoe Project	11	11	11	11	11	11	11
Salt Lake City Area Integrated Projects [f]	5,084	5,191	5,314	5,435	5,466	5,472	5,469
Total, Energy Sales	31,461	34,801	34,830	35,570	35,750	35,969	36,164

[a] For most power systems, sales amounts are based on FY 2005 Power Repayment Studies (PRS). The estimates for Central Arizona, Falcon-Amistad, and Provo River projects are based on average sales over the prior five years.
[b] One gigawatthour (GWh) equals one million kilowatt-hours (kWh).
[c] FY 2006 sales estimates for the Central Valley Project assumed power delivery at reduced levels pending establishment of outyear project use and negotiation of customer Custom Product contractual requirements.
[d] Loveland Area Projects include Fryingpan-Arkansas Project and the Western Division of the Pick-Sloan Missouri Basin Program.
[e] Pacific Northwest-Southwest Intertie shows no energy sales, but reflects revenues from the transmission of energy (refer to the Estimate of Revenues table). The Intertie Project is for transmission of energy only.
[f] Salt Lake City Area Integrated Projects include the Colorado River Storage Project, Collbran Project, Rio Grande Project, Seedskadee Project, and Dolores Project.

Estimate of Proprietary Receipts

(dollars in thousands)

	Actual FY 2006	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012
Mandatory							
Falcon Amistad Maintenance Fund, 895178	2,291	2,500	2,500	2,627	2,734	2,845	2,962
Sale and transmission of electric power, Falcon and Amistad Dams, 892245	2,818	2,466	2,372	2,269	2,161	2,049	1,931
Sale of Power and Other Utilities Not Otherwise Classified, 892249	-13,409	30,000	30,000	30,000	30,000	30,000	30,000
Sale of Power–Western–Reclamation Fund, 895000.27	227,107	226,033	199,967	184,751	206,131	172,585	182,016
Total, Mandatory Receipts	218,807	260,999	234,839	219,647	241,026	207,479	216,909
Discretionary							
Offsetting Collections from the recovery of power related expenses – Western – 89X5068.01	257,954	274,852	258,702	268,219	269,086	274,585	279,023
Less Purchase Power and Wheeling expenses	-257,954	-274,852	-258,702	-268,219	-269,086	-274,585	-279,023
Subtotal, 89X5068.01	0	0	0	0	0	0	0
Total, Discretionary Receipts	0	0	0	0	0	0	0
Total, Proprietary Receipts	218,807	260,999	234,839	219,647	241,026	207,479	216,909

Pending Litigation

Pending litigation that may impact Western's FY 2008 Congressional Budget request includes:

- ***California Power Exchange Corp*., United States Bankruptcy Court, Central District of California, Case No. LA 01-16577-ES**. On March 9, 2001, the California Power Exchange (PX) filed for bankruptcy under Chapter 11 of the Federal Bankruptcy Code. The filing was necessary after the PX had ceased operations on January 31, 2001. The PX could not operate after that date because it was not being paid by Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) for purchases they were making from the PX. Western is owed approximately $6.7 million by the PX. Western has filed a claim in the case and is being represented by bankruptcy counsel from the Department of Justice (DOJ) in Washington, DC. Final settlement of the bankruptcy is complicated due to the interrelationship of this case and many others stemming from the dysfunctional California electricity markets in 2000 and 2001. In order to pay its debts, the PX must ultimately be able to collect significant sums from PG&E and SCE. PG&E was itself in bankruptcy and SCE was in default for most of its obligations. The resolution of PG&E's bankruptcy has assisted in final resolution of the PX's bankruptcy. PG&E has escrowed significant funds to cover its obligations to the PX, as has SCE.

  The PX has a court approved Reorganization Plan. Much of the plan is dependent on certain approvals being made by FERC. FERC must address among other issues; the allocation of defaults among participants in the PX markets, the disposition of collateral, the calculation of "refunds" in the "Refund Case" (See FERC Docket Nos. EL00-95-000, et al., below), and the winding up of litigation related to the PX markets. Current litigation at FERC against the PX includes claims from PowerEx and other PX participants for return of collateral.

  Additionally, to wind up its FERC related activities, the Reorganized PX requires funding. In July 2002, the PX made a Section 205 application to FERC for approval of a rate schedule that would permit PX to charge its participants for their appropriate share of the costs of winding up its operations. The PX estimated that it will require approximately $35 million that should be set aside from the Settlements and Clearing Accounts to secure payment of these administrative charges to its participants. FERC approved the rate schedule in August, 2002. In July 2004, the Court of Appeals for the DC Circuit struck down the rate, concluding it violated the "filed rate doctrine" and amounted to impermissible retroactive rate making. Settlement proceedings have successfully reached a new rate for the PX, and that settlement was filed with FERC on September 1, 2005, and is pending FERC approval.

  Additionally, as part of the rate settlement discussed above, California State court proceedings related to "inverse condemnation" of the "block forward" contracts that were seized by former California Governor Davis immediately following the PX's initial defaults in January 2001 will be dismissed. Similarly, litigation against former directors and officers for allegations of malfeasance at the time of the PX's demise in 2001 will be dismissed in exchange for cash settlements with the "Director and Officer" insurers. The PX has made filings with the appropriate fora to effectuate the settlement. There have been no significant new developments since the last report.

- ***Quechan Indian Tribe vs. United States*, United States District Court, Southern District of California, Docket No. 02 CV 01096 JH (AJB)**. On June 7, 2002, the Quechan Indian Tribe filed suit in Federal District Court in its own capacity, and as *parens patriae* on behalf of its members, seeking declaratory and injunctive relief and $9.4 million in damages relating to the alleged impact to cultural sites that occurred within the Tribe's Fort Yuma Reservation located in Imperial County, California. The causes of action against Western are for money damages for injury or loss of property caused by the alleged negligent or wrongful acts or omissions of federal employees while acting within the scope of their office or employment when doing work on a project known as the Gila-Knob Pole 161-Kv Wood Pole Rehabilitation Project. The United States filed an Answer on October 22, 2002.

  In July 2003, the Parties applied for and were granted a stay of the present litigation pending a ruling by the United States Supreme Court in a case that addressed whether the Tribe ceded ownership of its reservation in 1893. *See Arizona v. California*, 530 U.S. 392 (2000). A ruling by the Supreme Court could have resulted in the Tribe losing its interest in its Reservation which would impact nearly all of the Tribe's claims in the present lawsuit. However, the parties settled the Supreme Court litigation. The Solicitor General's office requested comments from Western on the terms of the Supreme Court Settlement and Western formally objected to the language permitting the Tribe to retain all arguments in this case.

  Following the Supreme Court settlement, the United States and the Tribe negotiated, and the Court approved, a Case Management Order that sets forth the following four phased approach: (Phase 1) fact discovery (which was completed on June 10, 2005); (Phase 2) summary judgment motions; (Phase 3) expert discovery; and (Phase 4) pretrial proceedings.

  The Parties are now in Phase 2, and the Parties filed Cross Motions for Summary Judgment on September 2, 2005, Responsive Briefs on November 4, 2005, and Reply Briefs on December 9, 2005. Oral argument was held on January 11, 2006, and we are waiting on a ruling from the U.S. District Court Judge. There have been no significant developments.

Federal Energy Regulatory Commission Litigation

- ***California Independent System Operator Corp.*, Docket ER01-313-000 and *Pacific Gas and Electric Company*, Docket No. ER01-424-000 (consolidated).** In docket ER01-313-000, the California Independent System Operator Corporation (CAISO), tendered for filing an unbundled Grid Management Charge (GMC) on November 1, 2000. The purpose of the GMC is to allow the CAISO to recover its administrative and operating costs. The CAISO requested that the unbundled GMC be made effective as of January 1, 2001.

  In docket ER01-424-000, PG&E tendered for filing a GMC Pass-Through Tariff on November 13, 2000. PG&E alleges that the filing seeks to recover the costs proposed in the CAISO's GMC filing in Docket No. ER01-313-000. PG&E further alleges that it is a new service. PG&E requests an effective date of January 1, 2001, or the date the Commission makes effective the CAISO's filing. In the alternative, PG&E argued it was allowed to modify the existing contracts to pass through the GMC. Western argued that PG&E was not offering a new service for its existing contract customers. Western also argued the GMC was unjust and unreasonable. Finally, Western argued the filing was insufficient.

On December 29, 2000, the Commission consolidated ER01-313-000 with ER01-424-000 and accepted the matter for filing and set the matter for evidentiary hearing. Western filed its answering testimony on August 17, 2001. Western filed a motion asking for summary judgment on the issue of whether PG&E could modify Western's existing contracts. The Presiding Judge granted Western's motion. As a result, the only issue at hearing was whether the charges were new services. From November 13, 2001 – December 20, 2001, the Presiding Law Judge heard the case. The Presiding Judge issued her initial decision on May 10, 2002.

The Initial Decision found that the charges for Control Area Service (CAS bucket) constituted a new service to PG&E's Control Area Agreement (CAA) customers, i.e. existing contract holders. The Initial Decision also found that charges for Market Operations (MO bucket) was not a new service for CAAs. Therefore, the Presiding ALJ ordered PG&E to make a compliance filing to reflect the existing charges for market operations under each CAA and those additional ISO MO charges. However, in the case of Western, the Presiding Judge acknowledged her earlier ruling on Summary Judgment that PG&E had not fulfilled its limited Section 205 rights under 2948A. Thus, PG&E is barred from amending Contract 2948A with the charges for MO, despite a compliance filing.

Western filed a brief on exceptions on June 10, 2002, asserting that the Initial Decision errs in finding that the CAS bucket constitutes a new service and violates Commission precedent. On May 2, 2003, the Commission issued an opinion affirming the Presiding Judge's opinion that the CAS pass through was a new service and reversing the Presiding Judge's finding that the MO component of the GMC was not a new service. On June 2, 2003, Western filed a request for rehearing. On January 23, 2004, the Commission issued an order denying Western's, and other parties, Requests for Rehearing. Western then requested that the Department of Justice seek judicial review of FERC's decision.

The Department of Justice filed a Petition for Review on March 22, 2004, and is seeking authorization from the Solicitor General's Office to pursue judicial review. In the meantime, numerous parties filed requests for rehearing on the Commission's Opinion 463-A, 106 FERC ¶61,032 (2004). As a result of these continued administrative proceedings, FERC Staff moved to stay the Circuit Court appeal proceedings and the Circuit Court granted that motion.

FERC granted the parties' requests for rehearing on Opinion 463-A and issued a ruling deferring further action on the request for rehearing pending a remand to the Administrative Judge for additional fact development on the limited issue of whether certain generators that are modeled by the ISO should be charged GMC based on a net meter read rather than on Control Area Gross Load ("CAGL"). On November 7, 2005, the Commission issued Opinion No. 463-B, 113 FERC ¶ 61,135, addressing the CAGL issue with respect to certain generators. Certain parties have filed Requests for Rehearing of Opinion No. 463-B, and, on January 6, 2006, the Commission issued an order allowing itself further time to consider the parties' Requests for Rehearing, and therefore, the D.C. Circuit appeal continues to be held in abeyance pending the Commission's ruling. On September 7, 2006, the Commission issued an order, Opinion No. 463-C, 116 FERC

¶ 61,224, denying the Request for Rehearing of Opinion No. 463-B. Certain parties filed a request for rehearing on Opinion No. 463-C. On November 9, 2006, the Commission issued an order Granting Request for Rehearing to allow additional time for consideration. Western requested that the Justice Department move to lift the D.C. Circuit stay, but the Justice Department concluded that the administrative proceedings needed to be completed prior to proceeding.

In the meantime, PG&E has sent invoices to Western for the GMC charges. Western, however, was unable to verify PG&E's loads on which it is basing the GMC charge. Therefore, Western was unable to pay the invoices. Also, Western's obligation to pay the invoice is dependent on the outcome of Western's D.C. Circuit Court appeal. On December 1, 2005, Western received a revised GMC bill from PG&E. On April 13, 2006, P&GE sent Western a Claim for Damages under the Contract Disputes Act (CDA) seeking $5.5 million for the remaining unpaid balance PG&E alleges Western owes for GMC. On June 12, 2006, Western sent PG&E a letter denying its claim. PG&E had 90 days from the date it received Western's denial to provide notice it intends to pursue an appeal with the agency board of contract appeals. Instead of appealing to the agency board of contract appeals, PG&E may bring an action directly in the United States Court of Federal Claims within 12 months of the date it received Western's decision. PG&E has not yet filed such a claim.

- ***Calpine Construction Finance Co., FERC Docket ER05-912-000***. On December 21, 2005, Calpine Corporation and numerous affiliates filed a Chapter 11 Reorganization with the Federal Bankruptcy Court in the Southern District of New York. Western has numerous contracts with Calpine and is closely monitoring the proceedings. In a typical month, Calpine pays Western over $1 million for transmission service under Western's Open Access Transmission Tariff. Western and Calpine executed an assurance agreement in May 2006. Under this agreement, Calpine will prepay Western 30 days in advance for transactions. Western bills Calpine 20 days in advance. Western filed its proofs of claim in April 2006 for more than $1 million for certain pre-petition transactions. The parties are awaiting action from the court.

- ***Pacific Gas and Electric Company*, Docket Nos. ER04-242, EL04-50**. In this companion case to ER01-424-000, PG&E tendered for filing a GMC Pass-Through Tariff on November 26, 2003. PG&E alleges that the filing seeks to recover the costs proposed in the CAISO's GMC filing in Docket No. ER04-115-000. The ISO has further unbundled the GMC charges from its previous three buckets to seven buckets. All parties to this case, including PG&E and Western, entered into a settlement agreement providing that the 2004 GMC charges could be passed through to Western if the invoices are certified and verifiable and subject to the outcome of the Circuit Court appeal in ER01-424-000. The settlement barred the CAISO from modifying the GMC rate design until January 1, 2007. The CAISO has extended the rate design restriction until the earlier of December 31, 2007 or the implementation of the CAISO's Market Redesign and Technology Upgrade (MRTU).

- ***Pacific Gas and Electric Company*, FERC Docket No. ER05-229-000.** On November 17, 2004, Pacific Gas and Electric Company (PG&E) unilaterally submitted a Scheduling Coordinator Services (SCS) Tariff for Western. Under this Tariff, PG&E seeks to collect from Western the costs PG&E or its designated Scheduling Coordinator incurs on behalf of Western by acting as Western's Scheduling Coordinator for two existing long term transmission contracts. PG&E requests an effective date of December 31, 2004.

Western filed comments and a protest but did not intervene. Western indicated it has no intention of accepting PG&E's offer of service or taking service under PG&E's SCS Tariff, and Western did not submit to the Commission's jurisdiction. Nothing in Western's existing contracts with PG&E requires Western to take additional services to receive the benefits for which Western bargained. Nor do Western's existing contracts allow PG&E to charge Western for any additional services. PG&E has an obligation to deliver. Western has prepaid for those services and PG&E cannot charge Western any additional charges. Western has prepaid PG&E for transmission service, and as part of the bargain, PG&E accepted any and all risks that a change associated with the costs would occur. Finally, Western cannot be legally bound by PG&E's SCS Tariff. No federal contracting officer has executed the SCS Tariff or approved the tariff submitted by PG&E.

On December 30, 2005, the Commission issued an order accepting the filing and setting the matter for evidentiary hearing. From January 1, 2005-March 8, 2005, the parties attempted to settle the matter. On March 9, 2005, the Settlement Judge terminated the settlement proceeding. The Presiding Judge held a hearing on May 23, 2006. The Parties filed initial Post-hearing briefs on June 30, 2006. Reply briefs were scheduled to be filed July 18, 2006.

In the meantime, PG&E and Western engaged in further settlement discussions and stayed the proceedings. On September 5, 2006, PG&E filed the Offer of Settlement, Explanatory Statement, and Settlement with the Commission for consideration and approval. PG&E, at Western's request, filed a motion for expedited consideration that the Commission granted. Under the terms of the Settlement Agreement, Western and PG&E resolved outstanding disputes regarding PG&E's allegations that Western owes SC charges and Western's position that Western is owed a credit for the provision of reserves and over-delivery of energy. In addition, Western and PG&E agreed to transfer the SC responsibilities for the San Luis and New Melones generation and loads from PG&E to Western. Also as part of the Settlement, Western and PG&E agreed to amend the San Luis and New Melones Contracts to terminate or modify provisions that provide for the scheduling of generation, the true-up of capacity and energy amounts delivered compared to schedules, transmission losses, measurement of capacity and energy, and reactive power support for voltage control. On November 2, 2006, the Commission approved the settlement. As of December 2006, the parties are in the process of implementing the settlement. The case should close in January 2007.

In a connected case, on September 6, 2006, in a separate FERC Docket, Docket No. ER 06-1470, the ISO filed with the Commission for filing and acceptance a Pilot Pseudo Tie Implementation Agreement ("Pilot Agreement"), between the ISO, PG&E, SMUD, and Western. The Offer of Settlement in ER05-229 (described above) is contingent on Commission acceptance of the Pilot Agreement. In addition, as part of the Settlement in ER05-229, PG&E agreed to support and assist in the implementation of the Pilot Agreement. The purpose of the Pilot Pseudo Tie Implementation Agreement is to implement and operate a pilot program to provide for Pseudo Tie (i.e. remote tie) export arrangements for the New Melones Power Plant, which the United States Bureau of Reclamation owns and Western operates. Western is a sub-control area within the SMUD Control Area; the New Melones Power Plant is currently located in the ISO Control Area. The Pilot Agreement is intended to allow Western to schedule Energy and Ancillary Services, as a Pseudo Tie export, dynamically and using a Scheduling Coordinator, through the ISO Control Area into the SMUD Control Area. On October 23, 2006, the Commission accepted the filing. As of December 2006, the parties are in the process of implementing the agreement. This case should close in January 2007.

- ***San Diego Gas & Electric Company Investigation of Practices of the California Independent System Operator and California Power Exchange, California Electricity Oversight Board, et al.***, **Docket Nos. EL00-95-000, et al.** In the fall of 2000, the Commission began an investigation under Section 206 of the Federal Power Act into the dysfunctional California markets. The Commission has issued a series of orders addressing both price mitigation and potential refunds. The Commission eventually (June 19, 2001) ordered "hard" price caps in the California and WSCC spot markets. The Commission also made a finding that prices charged in the California markets were unjust and unreasonable. Important to Western was a Commission decision to assert jurisdiction over non-public utilities with regard to refunds.

  FERC issued rehearing orders on December 19, 2001, largely upholding the earlier Commission orders in the case, including jurisdiction over non-public utilities. Hearings were first held in March 2002 to calculate the appropriate mitigated market clearing prices and scope of refunds. Subsequent hearings on Issues II and III ("who owes what to whom") were held in August 2002. The Presiding ALJ did preliminarily decide that Western's CRSP "exchange transactions" with the ISO are not subject to refund.

  The Presiding ALJ issued his Initial Decision (ID) in December 2002. At approximately the same time, FERC responded to an order of the Ninth Circuit Court of Appeals in August 2002 that found that FERC had not developed an adequate record with respect to the extent of manipulation. FERC allowed an additional discovery period of 100 days. Western responded to over 140 data requests from the "California Parties" and organized a document repository at SNR. In March 2003, the Commission issued an order largely upholding the ID, but implementing Staff's recommendations related to gas prices, which had also been subject to manipulation during the refund period. Following the March 2003 Order, the Commission initiated proceedings to resolve outstanding issues relating to gas prices. These proceedings have continued and Western has worked in particular with the City of Redding regarding the filing of a Fuel Cost Allowance (FCA) claim on behalf of Redding. Notice of the FCA claim was filed with the Commission on April 1, 2005 and also submitted to the auditor, Ernst & Young, at that time. On August 30, 2005, Western submitted Redding's final FCA to the ISO.

  In September 2004, the Ninth Circuit ruled against the Commission and found that the Commission did in fact have authority to order refunds for the time period prior to October 2, 2000, based on the theory that certain sellers with market-based rate authority had failed to file required reports of sales with the Commission. The Commission has not yet issued any orders in response to the Ninth Circuit opinion, which should have no impact on Western.

  The ISO and PX have generally finished conducting "reruns" of the markets for the refund period in order to calculate refunds in accordance with the Commission's current rulings and formulae in the case. In December 2003, SNR and Montrose began receiving the first sets of rerun data for review and possible dispute proceedings. Latest indications from the ISO show it may still be many months before completion. The Commission has attempted to speed up the process in response to Congressional direction in the 2005 Energy Policy Act. The Act calls on FERC to attempt to resolve these proceedings by the end of 2005 and to provide Congress a progress report at that time. On August 8, 2005, the Commission issued an order, in part to amend the procedural schedules, in order to meet these new time requirements. That order also set procedures for the submission of revenue shortfall filings. Western evaluated the potential of making cost filings, but under current Commission directives, found that is was not advantageous to do so. The August 8 Order also included provisions for entities to file "final" disputes regarding ISO and PX reruns. Western also evaluated that possibility, but did not file any further disputes. The Commission continues to hear matters related to the cost filing and other offsets.

On December 23, 2004, initial briefing also began in the Ninth Circuit regarding certain threshold issues and oral arguments were heard in mid-April 2005 on a number of issues including jurisdiction and the scope of transactions subject to refund. On September 6, 2005, the Ninth Circuit ruled that FERC did not have the authority under the Federal Power Act to order refunds from governmental sellers, such as Western, in these proceedings. The ruling is subject to appeal, either back to the Ninth Circuit or to the United States Supreme Court. Until such time as the ruling is final and FERC takes action in accordance with the ruling, Western may still need to participate in continued proceeding in order to preserve procedural rights.

On December 5 and 29, 2005, Western received claims (under the Contract Disputes Act or CDA) from the California Parties in the approximate amount of $30 million. This action is in response to the 9th Circuit's rejection of FERC of jurisdiction over Western, BPA and other governmental sellers. Because of their setback at the 9th Circuit, the California Parties have turned to the filing of administrative contractual claims against Western, BPA (under the CDA) and the other governmental sellers (as administrative claims under California State law). The California Parties rely on a portion of the 9th Circuit's opinion where the Court, while rejecting FERC's authority to order refunds under the FPA, raises the possibility of contract based actions. The 9th Circuit cites to FERC and Federal court proceedings to support this possibility. Western requested further information to support the claims. The California Parties refused to provide such information and on March 23, 2006, the claims were denied. In May 2006, BPA initiated settlement discussions with the California Parties. Western was invited to participate in those discussions. Nothing substantive has come from these discussions other than a clearer understanding of the claimed amount by the California Parties, which now appears to be closer to $14 million demanded, and approximately $12 million owed to Western as receivables.

In August 2006, the 9th Circuit issued an opinion in the "Scope Cases" finding that FERC did generally have authority to order refunds for the "Summer 2000" period and for exchange transaction; however, the 9th Circuit did find that "CERS transactions (bi-lateral sales made to the California Department of Water Resource's - California Energy Resources Scheduling Division)" were not subject to refund. These changes to the scope of the case arguably increase Western's overall refund liability by as much as $6 million, although those numbers have not yet been calculated by FERC. Following this decision, the 9th Circuit also initiated a new settlement process in these proceedings, with the first settlement conference held in San Francisco on September 19, 2006. A further meeting was held in Pasadena in November between the various municipal sellers (including Western and BPA) and the mediators. Western is still considering a counteroffer to the California Parties.

Bonneville Power Administration

Bonneville Power Administration

Bonneville Power Administration

Proposed Appropriations Language

Expenditures from the Bonneville Power Administration Fund, established pursuant to Public Law 93-454, are approved for the Lower Granite Dam fish trap, the Kootenai River White Sturgeon Hatchery, the Nez Perce Tribal Hatchery, Redfish Lake Sockeye Captive Brood expansion, hatchery production facilities to supplement Chinook salmon below Chief Joseph Dam in Washington, Hood River Production Facility, Klickitat production expansion, Mid Columbia Coho restoration, and Yakama Coho restoration, and, in addition, for official reception and representation expenses in an amount not to exceed $1,500.

During fiscal year 2008, no new direct loan obligations may be made.

Bonneville Power Administration

Overview

Summary by Program

(accrued expenditures in thousands of dollars)

	FY 2006	FY 2007	FY 2008
Capital Investments			
Power Services	176,033	201,000	213,000
Transmission Services	138,474	226,821	278,059
Capital Equipment & Bond Premium	17,671	32,785	47,421
Total, Capital Investments	332,178	460,606	538,480
Accrued expenditures will require budget obligations of	332,178	460,606	538,480
Operating Expenses	2,523,739	2,779,011	2,608,506
Projects Funded in Advance	47,917	138,883	77,494
Capital Transfers (cash)	696,919	386,541	686,068
BPA Net Outlays	(917,000)	(9,000)	(93,000)
BPA Staffing (FTE)	2,923	3,000	3,000

Outyear Summary

(accrued expenditures in thousands of dollars)

	FY 2009	FY 2010	FY 2011	FY 2012
CAPITAL INVESTMENTS				
Power Services	205,000	199,000	200,000	211,000
Transmission Services	253,083	281,487	280,900	299,977
Capital Equipment & Bond Premium	32,187	31,363	26,116	27,170
Total, Capital Investments	490,270	511,850	507,016	538,147
Accrued expenditures will require budget obligations of	490,270	511,850	507,016	538,147
Operating Expenses	2,894,485	2,708,216	2,792,553	2,699,924
Projects Funded in Advance	76,557	69,052	71,055	63,616
Capital Transfers (cash)	404,408	518,711	468,451	395,886
BPA Net Outlays	(97,000)	(95,000)	(104,000)	(99,000)
BPA Staffing (FTE)	3,000	3,000	3,000	3,000

Overview

The accompanying notes are an integral part of this table.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

Bonneville's program is treated as mandatory and nondiscretionary. As such, Bonneville is "self-financed" by the ratepayers of the Pacific Northwest and is not annually appropriated by Congress. Thus, a FY 2007 Continuing Resolution will not impact program funding during the year except where new requested bill language was not provided. Under the Transmission System Act, Bonneville funds the expense portion of its budget and repays the Federal investment with revenues from electric power and transmission rates.

Proposed FY 2008 appropriation language providing for approval for construction of new fishery facilities as authorized by the Pacific Northwest Electric Power and Planning Act for new fish and wildlife facilities of $1 million and an economic life greater than 15 years (PL 96-501, sec.4.(H)(10)(B)), includes those projects proposed for approval in FY 2007 and other projects proposed for approval in FY 2008.

Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that along with actual market conditions will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated net outlay estimates could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, however causing the same net outlay result. Adjustments for depreciation and 4(h)(10)(C) are also assumed.

Amortization/Capital Transfer estimates in this budget, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President's budget. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and other variables that may affect the opportunity for advanced amortization payments.

Amounts of such estimated payments to Treasury vary from associated net secondary revenues and debt optimization amounts due to timing of Treasury payments and other factors. Actual net secondary revenues and debt optimization effects would vary due to volatility of secondary power markets, streamflow variability, volatility of financial markets affecting ENW debt optimization, and other uncertainties.

The cumulative amount of actual advance amortization payments as of the end of FY 2006 is $1,802 million.

FTE outyear data are estimates and may change.

Preface

The Bonneville Power Administration (Bonneville or BPA) serves the Pacific Northwest through operating an extensive electricity transmission system and marketing wholesale electrical power at cost from Federal dams and other non-Federal generating units including some wind energy generation facilities.

The organization of Bonneville's FY 2008 budget reflects Bonneville's business services basis for utility enterprise activities. Bonneville's two major areas of activity on a consolidated budget and accounting basis include Power Services (PS) and Transmission Services (TS) with administrative costs included. The PS includes line items for Fish and Wildlife, Conservation and Energy Efficiency, Residential Exchange Program (REP), Associated Projects O&M Costs, and Northwest Power and Conservation Council (Planning Council, Council).

Mission

The strategic mission of Bonneville as a public service organization is to create and deliver the best value for its customers and constituents as it acts in concert with others to assure the Pacific Northwest:

- An adequate, efficient, economical and reliable power supply;
- A transmission system that is adequate to the task of integrating and transmitting power from Federal and non-Federal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and
- Mitigation of the Federal Columbia River Power System (FCRPS) impacts on fish and wildlife.

As BPA shapes programs and planns spending levels, it is driven by its strategic vision that encompasses the following four pillars:

- High system reliability short-and long term through effective management,
- Low rates consistent with sound business principles that are predictable and have low volatility,
- Responsible environmental stewardship, and
- Accountability to the region through increased transparency and collaborative partnerships.

Bonneville is committed to cost-based rates, open and non-discriminatory transmission access, and public and regional preference in its marketing of power. Bonneville will set its rates as low as possible consistent with sound business principles and the full recovery of all of its costs, including timely repayment of the Federal investment in the system.

Benefits

Bonneville provides electric power (about 40 percent of the electricity consumed in the region), transmission (more than three-fourths of the region's high voltage transmission capacity), and energy efficiency throughout the Pacific Northwest, a 300,000 square mile service area. Bonneville markets the electric power produced from 31 operating Federal hydro projects in the Pacific Northwest owned by the U.S. Corps of Engineers (Corps) and the U.S. Department of Interior, Bureau of Reclamation (Reclamation), and also acquires non-Federal power, including the power from the Columbia Generating Station, to meet the needs of its customer utilities. Bonneville owns and operates over 15,000 circuit miles of lines, 238 substations and associated power system control and communications facilities over which this electric power is delivered. Bonneville also supports the protection and enhancement of fish and wildlife, and provides leadership in conservation and renewables development, as part of its efforts to preserve and balance the economic and environmental benefits of the FCRPS.

Bonneville's strategic direction establishes the agency's most important long-term objectives and the actions that will help it manage to these objectives. The strategic direction calls on BPA to advance the Pacific Northwest's future leadership in four core values: high reliability, low rates consistent with sound business principles, responsible environmental stewardship, and clear accountability.

Strategic Themes and Goals and GRPA Unit Program Goals

The Department of Energy's (Department or DOE) Strategic Plan identifies five Strategic Themes (one each for nuclear, energy science, management, and environmental aspects of the mission plus sixteen Strategic Goals that tie to the Strategic Themes). The Bonneville program supports the following goal:

Strategic Theme 1, Energy Security: Promoting America's energy security through reliable, clean, and affordable energy.

Strategic Goal 1.3 Energy Infrastructure: Create a more flexible, more reliable, and higher capacity U.S. energy infrastructure.

Bonneville's Government and Results Performance Act (GRPA) Unit Program Goal contributes to the Strategic Goals in the "goal cascade." This goal is to Market and Deliver Federal Power:

GRPA Unit Program Goal 01.03.18.00: Bonneville Power Administration. Market and Deliver Federal Power: Ensure Federal hydropower is marketed and delivered while passing the North American Electric Reliability Council's (NERC) Control Compliance Ratings, meeting planned repayment targets, and achieving targeted hydropower generation efficiency performance.

Contribution to Strategic Goal

Bonneville contributes to this strategic goal through its strategic vision to advance a Northwest power system that is a national leader in providing reliability, low rates consistent with sound business principles, environmental stewardship, and accountability to the region. BPA has renewed its emphasis on performance and has adopted 27 agency-wide objectives for FY 2007 that are key to achieving its mission. These objectives, aligned using the balanced scorecard model, are focused on stakeholder value, financial performance, internal operations, and people and culture. Bonneville's infrastructure investments in the Pacific Northwest to meet power and transmission needs continue to support DOE's strategic goal on energy infrastructure.

Bonneville's strategic direction has helped to identify a number of key long-term issues. These issues center on providing Bonneville customers with certainty over load service obligations and enabling customers and the market to respond with the necessary electric industry infrastructure investments. Other key strategic interests include general market stability, BPA risk management, and long-term assurance of funding to repay the U.S. Treasury (Treasury) investment in infrastructure. Bonneville is now addressing these key issues through the Regional Dialogue, BPA's post-2011 power marketing planning process.

Funding by Strategic and GRPA Unit Program Goal

(accrued expenditures in thousands of dollars)

	FY 2006	FY 2007	FY 2008
Strategic Theme 1, Energy Security			
Strategic Goal 1.3 Energy Infrastructure			
GRPA Unit Program Goal 01.03.18.00, Market and Deliver Federal Power			
Bonneville Power Administration			
Capital Investments			
Power Services	176,033	201,000	213,000
Transmission Services	138,474	226,821	278,059
Capital Equipment & Bond Premium	17,671	32,785	47,421
Total Capital Investments	332,178	460,606	538,480
Accrued expenditures will require budget obligations of	332,178	460,606	538,480
Operating Expenses	2,523,739	2,779,011	2,608,506
Projects Funded in Advance	47,917	138,883	77,494
Capital Transfers (cash)	696,919	386,541	686,068
Net Outlays	(917,000)	(9,000)	(93,000)
BPA Staffing (FTE)	2,923	3,000	3,000

Outyear Funding by Strategic and GRPA Unit Program Goal

(accrued expenditures in thousands of dollars)

	FY 2009	FY 2010	FY 2011	FY 2012
Strategic Theme 1, Energy Security				
Strategic Goal 1.3 Energy Infrastructure				
GRPA Unit Program Goal 01.03.18.00, Market and Deliver Federal Power				
Capital Investments				
Power Services	205,000	199,000	200,000	211,000
Transmission Services	253,083	281,487	280,900	299,977
Capital Equipment & Bond Premium	32,187	31,363	26,116	27,170
Total Capital Investments	490,270	511,850	507,016	538,147
Accrued expenditures will require budget obligations of	490,270	511,850	507,016	538,147

	(accrued expenditures in thousands of dollars)			
	FY 2009	FY 2010	FY 2011	FY 2012
Operating Expenses	2,894,485	2,708,216	2,792,553	2,699,924
Projects Funded in Advance	76,557	69,052	71,055	63,616
Capital Transfers (cash)	404,408	518,711	468,451	395,886
Net Outlays	(97,000)	(95,000)	(104,000)	(99,000)
BPA Staffing (FTE)	3,000	3,000	3,000	3,000

Funding by General and Program Goal

The accompanying notes are an integral part of this table.

Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that along with actual market conditions will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated net outlay estimates could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, however causing the same net outlay result. Adjustments for depreciation and 4(h)(10)(C) are also assumed.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

FTE outyear data are estimates and may change.

Annual Performance Results and Targets

FY 2003 Results	FY 2004 Results	FY 2005 Results	FY 2006 Targets	FY 2007 Targets	FY 2008 Targets
Strategic Goal 1..3, Energy Infrastructure Met Goal Actual: CPS1: 198.0% CPS2: 93.6%	Met Goal Actual: CPS1: 198.5% CPS2: 94.3%	Met Goal Actual: Met CPS1: 196.6% CPS2: 93.9%	Met Goal Actual: Met CPS1: 193.3% CPS2: 96.1%	Attain average NERC compliance ratings for the following NERC Control Performance Standards (CPS) measuring the balance between power generation and load, including support for system frequency: (1) CPS-1, which measures generation/load balance on one-minute intervals (rating >=100); and (2) CPS-2, which limits any imbalance magnitude to acceptable levels (rating >=90).	Attain average NERC compliance ratings for the following NERC Control Performance Standards (CPS) measuring the balance between power generation and load, including support for system frequency: (1) CPS-1, which measures generation/load balance on one-minute intervals (rating >=100); and (2) CPS-2, which limits any imbalance magnitude to acceptable levels (rating >=90
Met Goal ($216 million) Actual: $544 million	Met Goal ($246 million) Actual: $592 million	Met Goal ($303 million) Actual: $618 million	Met Goal ($304 million) Actual: $646 million	Meet planned annual repayment of principal on Federal power investments.	Meet planned annual repayment of principal on Federal power investments.
		Hydropower Generation Efficiency Performance: Met Goal (97%) Actual: 100% (EOY)	Hydropower Generation Efficiency Performance: Met Goal (97%) Actual: 100% (EOY)	Hydropower Generation Efficiency Performance: Achieve 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Corps, and Reclamation.	Hydropower Generation Efficiency Performance: Achieve 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Corps, and Reclamation.

Annual Outyear Performance Targets

FY 2009 Targets	FY 2010 Targets	FY 2011 Targets	FY 2012 Targets
Strategic Goal.3.1, Energy Infrastructure			
Transmission System Reliability Performance: Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.	Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.	Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.	Attain average NERC compliance ratings for the NERC CPS measuring the balance between power generation and load, including support for system frequency.
Repayment of Federal Power Investment: Meet planned annual repayment of principal on Federal power investments.	Meet planned annual repayment of principal on Federal power investments.	Meet planned annual repayment of principal on Federal power investments.	Meet planned annual repayment of principal on Federal power investments.
Hydropower Generation Efficiency Performance: Achieve 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Corps, and Reclamation.	Achieve 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Corps, and Reclamation.	Achieve 97.5% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Corps, and Reclamation.	Achieve 98% Heavy-Load-Hour Availability (HLHA) through efficient performance of Federal hydro-system processes and assets, including joint efforts of BPA, Corps, and Reclamation.

BPA is continuing to assess target measures that achieve the best alignment with its strategic objectives.

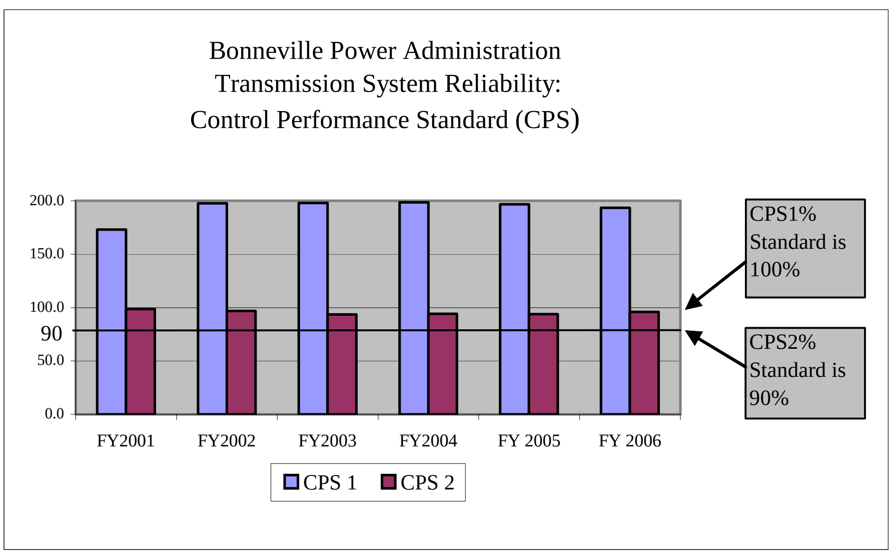
The Hydropower Generation Efficiency Performance Target is included in this FY 2008 budget as a performance measure starting in FY 2005. Historical data for this measure includes FY 2003 Goal 97%, Actual 97%; FY 2004 Goal 97%, Actual 100%.

Transmission System Reliability Performance Indicator

This indicator defines a standard of minimum monthly control performance as established by the NERC. Each control area within the system is to operate above minimum monthly control compliance ratings that can be achieved within the bounds of reasonable economic and physical limitations. Each control area is to monitor its control performance continuously against two standards, CPS 1 and 2.

The CPS-1 and CPS-2 performance indicators are industry standards that U.S. and Canadian electric utilities use in conjunction with NERC to help assure the reliability of the North American high voltage distribution system, and thereby to benefit the public. These measures are intended to indicate whether or not electric utility systems are being operated within acceptable operating parameters. Any deviation from the minimum standards must be reported to NERC. CPS-1 helps assure generation and load balance. CPS-2 helps limit the magnitude of any imbalance to acceptable levels, and provides a frequency sensitive evaluation of how well a control area meets its demand requirements.

Transmission System Reliability Target in FY 2008: Attain average NERC compliance ratings for the following NERC CPS measuring the balance between power generation and load, including support for system frequency: (1) CPS-1, which measures generation/load balance on one-minute intervals (rating >=100); and (2) CPS-2, which limits any imbalance magnitude to acceptable levels (rating >=90).



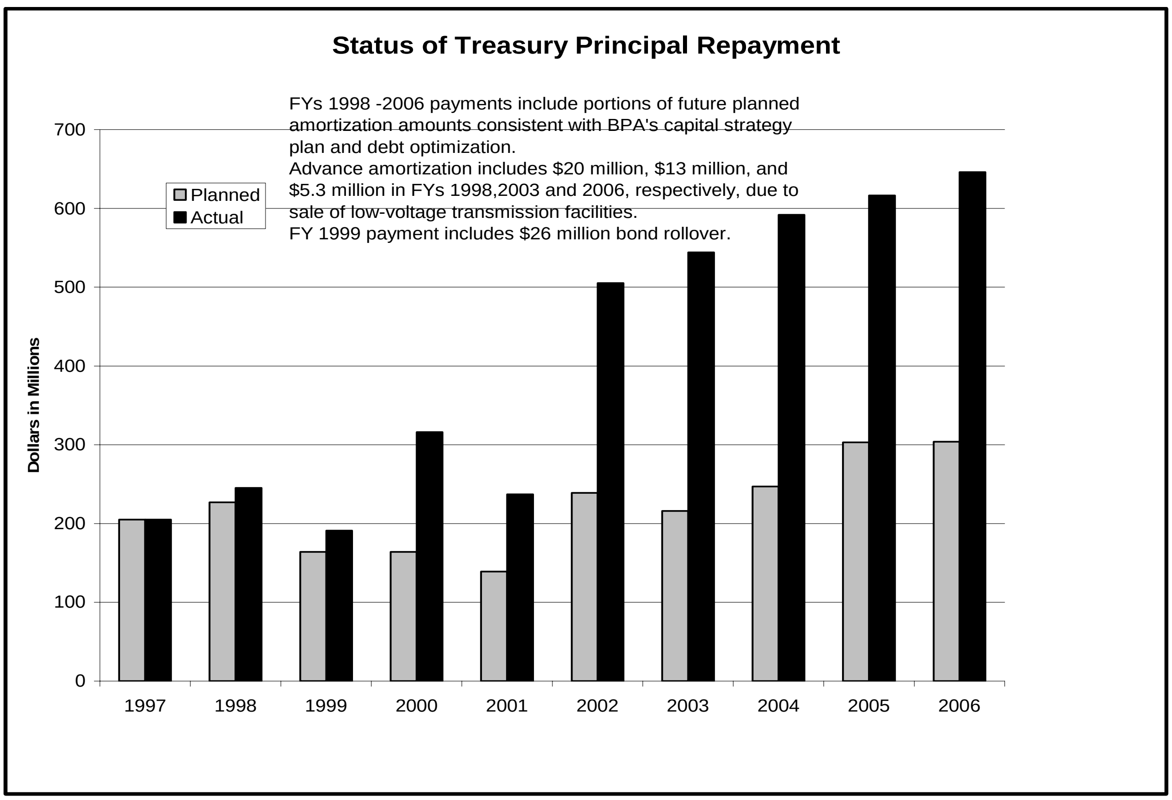
Repayment of Federal Power Investment Performance Indicator

This indicator measures the variance of actual from planned principal payments to the Treasury.

Treasury payment outyear estimates for planned amortization or principal are based on rate case estimates when available and planned amortization for future rate case periods. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and advanced amortization payments. In recent years, BPA has made amortization payments in excess of those scheduled in its Federal Energy Regulatory Commission (FERC)-approved rate filings, resulting in a balance of advance repayment. Bonneville made its full planned FY 2006 payment of $1,113 million to the Treasury is comprised of $697 million in amortization that includes $342 million in advanced amortization, $389 million in interest, and $27 million of Unfunded CSRS liabilities and Associated Project Costs.

> Repayment target in 2008 – Meet planned repayment of principal on Federal power investments in FY 2008.

The following chart displays principal repayment only.



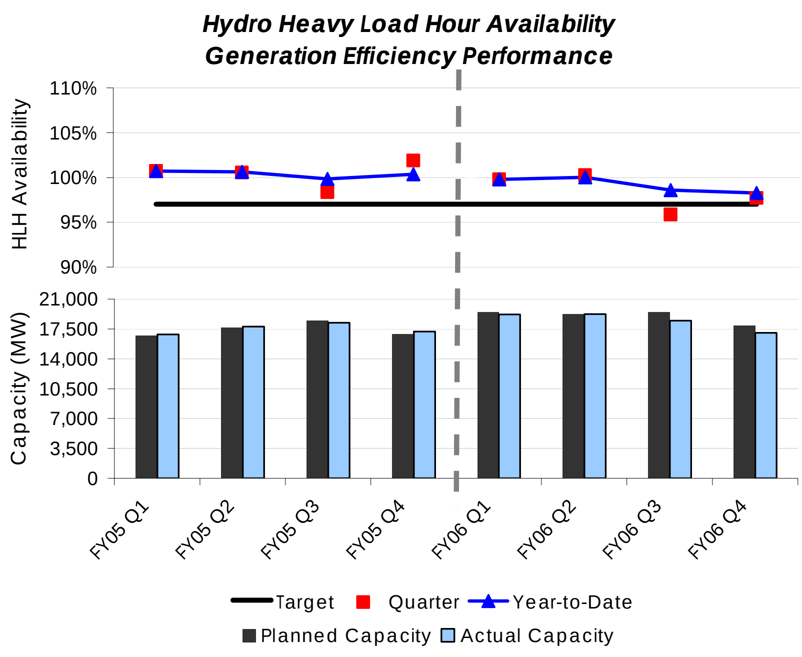
Hydropower Generation Efficiency Performance Indicator

The fundamental programmatic role of Bonneville within the FCRPS is the marketing of electricity generated at the multi-purpose hydro projects in the Pacific Northwest owned and operated by the Corps and Reclamation. HLHA concerns the actual effective performance of the hydro system, reflecting joint work between BPA, the Corps, and Reclamation to improve performance of these generating projects when they are needed most for commercial power operation. It is important from a reliability and economic standpoint to have power generation available when loads are high.

HLHA is the ratio of actual available machine capacity during heavy load hours, divided by planned available capacity during heavy load hours, expressed as a percent.

Actual available machine capacity is measured directly from data supplied from the hydro plants. Planned available capacity is established annually through the Annual Outage planning process, then updated quarterly based on changes in load and water forecasts. The resulting outage plans are stored in BPA's Outage Database.

> Hydropower Generation Efficiency target: Achieve actual efficiency results at or above planned availability target levels for hydropower generation efficiency.



As represented above, in 2006 the FCRPS hydro performance tracked closely to the HLHA targets, meeting the targets in all four quarters.

Means and Strategies

Bonneville provides electric power, transmission, and energy services while supporting the achievement of its vital responsibilities for fish and wildlife, energy conservation, renewable resources, and low-cost power in the Pacific Northwest.

BPA's strategic direction and balance scorecard establish a key objective of meeting electricity availability, adequacy, reliability, and cost-effectiveness standards through performance and expansion of the transmission system. The strategic direction and balance scorecard efforts include a long-term vision of Bonneville's future and an assessment of critical environment factors and key objectives. The vision and assessment help direct Bonneville activities needed to meet its mission over the long-term. The objectives are supported by multi-year targets to lay out the long-term course for achieving the objectives.

To improve system adequacy, reliability and availability, BPA has embarked on major transmission infrastructure projects. The projects shore up the region's transmission system and help meet the region's future power needs. These projects address multiple challenges, such as the need to relieve a number of congested transmission paths, the pressure to keep up with growing energy demands, and the need to meet FERC's open access policy in support of competitive markets.

For FY 2008 BPA's total transmission capital budget includes $356million for main grid additions, upgrades and additions, system replacements, area and customer services, and projects funded in advance. These investments - repaid entirely by revenues from BPA's customers or benefiting third parties - are foundational to BPA's transmission performance.

As part of BPA's strategic direction, Bonneville is also working to improve efficiency and initiate further cost reductions. Bonneville coordinates its power operational activities with the Corps, Reclamation, NERC, regional electric reliability councils, its customers, and other stakeholders to provide the most efficient use of Federal assets. Ongoing work with the Corps and Reclamation is focused on improving the reliability of the FCRPS, increasing its generation efficiency and optimization of hydro facility operation.

In addition, Bonneville is committed to continue funding its share of the region's efforts to recover fish and wildlife species in the Columbia Basin under the Endangered Species Act (ESA). BPA works closely with the Council, regional fisheries managers, the U.S. Fish and Wildlife Service (USFWS), the Corps and Reclamation, as well as other Federal agencies to prioritize and manage fish and wildlife program projects.

Bonneville initiatives are impacted by external factors such as continually changing economic and institutional conditions in the electric utility industry, competitive dynamics, and the continued restructuring of the electric industry.

Private and public sector partners have been and continue to be an important part of BPA's collaborative efforts to promote and foster efficient use of energy. BPA has initiated efforts to explore non-Federal financial participation in its transmission infrastructure projects with transmission customers and others in the region. The recent BPA power rate setting process supported a high level of cooperation and collaboration with customers and other rate case parties resulting in significant cost efficiencies and enhanced risk management approaches. Additionally, BPA is partnering with and assisting a DOE Wind Power crosscutting initiative to strengthen energy security by adding alternative sources of renewable energy.

Additional activities and products contributing to BPA's long-term achievement of its mission include the Regional Dialogue, an enhanced capital asset management plan, a workforce plan that addresses the long-term staffing needs of the agency, and continuing efforts to increase operational efficiencies. A separate Innovative Technology office within BPA leads the long-term strategy development and management for research, development, demonstration and deployment of new technology by BPA. BPA is also working to incorporate the numerous aspects of the Energy Policy Act of 2005 related to its business, in particular transmission reliability, energy supply, conservation, and new energy technologies for the future.

Validation and Verification

To validate and verify program performance, Bonneville conducts various internal and external reviews and audits. Bonneville's programmatic activities are subject to review by Congress, the General Accountability Office (GAO), the Department's Inspector General, and other governmental entities. Bonneville accounts are reviewed annually by an independent outside auditor. In addition, BPA uses Institute of Electrical and Electronics Engineers standard measures to monitor and evaluate system reliability performance, and participates yearly in an independent reliability benchmarking study.

Program Assessment Rating Tool (PART)

The Department implemented a tool to evaluate selected programs. PART was developed by the Office of Management and Budget (OMB) to provide a standardized way to assess the effectiveness of the Federal government's portfolio of programs. The structured framework of the PART provides a means through which programs can assess their activities differently than through traditional reviews.

The current focus is to establish outcome- and output-oriented goals, the successful completion of which will lead to benefits to the public, such as increased national security and energy security, and improved environmental conditions. BPA has incorporated feedback from OMB into the FY 2008 budget submission, and will take the necessary steps to continue to improve performance.

In the 2004 PART review by OMB, Bonneville received high scores of 89 and 100 in the Planning and Management sections. These high scores reflect Bonneville's strong program management system and internal and external program and management reviews. Bonneville's somewhat lower scores in the Purpose and Results sections were attributed in part to its rate setting processes and the need for improved performance measures. Enactment of the adjustable BPA power rate to accommodate changing water conditions and financial performance is an example of how BPA is working to continuously improve its rates processes and utilize rate setting as a tool to protect the taxpayer's investment in the FCRPS. This rate adjustment helped BPA establish its rates with a targeted Treasury payment probability over 90 percent for the FY 2007-2009 rate period. BPA's FY 2006 Treasury payment marks the 23rd consecutive year that BPA has made its payment on time and in full.

Regarding PART feedback on performance measurement, BPA has re-examined its overall strategic vision and associated performance measures, enhancing the linkage between its financial performance and strategy. BPA's long-term agency objectives are presented through a strategy map that expresses a direct link of overall agency direction to the objectives and targets of internal organizations. Managers' performance contracts also relate directly to organization and agency targets. In addition, BPA is continuing to continuing to develop vision related efficiency measures and targets, both short-term and long- term.

With respect to the marketing and cost recovery findings, BPA has initiated a multi-year, agencywide efficiency drive—the Enterprise Process Improvement Program (EPIP). The EPIP has already led to consolidation and centralization of several agency functions, elimination of redundancies and establishment of consistent processes. The resulting transition from a business line basis of organization to a services structure is reflected in this FY 2008 budget. The second phase of the EPIP program is focusing on asset management, marketing and sales, and the materials supply chain. BPA is also in the process of implementing an enterprise-wide asset management approach that will provide a common centralized framework for prioritizing asset spending across all asset management categories.

Program Perspectives

This section provides an introduction to Bonneville operations and statutory authorities followed by a description of ongoing activities.

Bonneville is DOE's electric Power Marketing Administration for the FCRPS. Bonneville provides electric power, transmission, and energy efficiency throughout the Pacific Northwest. Created in 1937 to market and transmit the power produced by the Bonneville Dam on the Columbia River, Congress has since directed Bonneville to sell at wholesale the electrical power produced from 31 operating Federal hydro projects and to acquire non-Federal power and conservation resources sufficient to meet the needs of Bonneville's customer utilities. Bonneville also owns and operates over 15,000 miles of high-voltage transmission lines, transmitting power from the dams and other sources on an open-access non-discriminatory basis. Bonneville serves a 300,000 square mile area including Oregon, Washington, Idaho, Western Montana, and parts of Northern California, Nevada, Utah, and Wyoming.

The Bonneville Project Act of 1937 provided the foundation for Bonneville's statutory utility responsibilities and authorities. In 1974, passage of the Federal Columbia River Transmission System Act (Transmission System Act) placed Bonneville under provisions of the Government Corporation Control Act (31 U.S.C. 9101-9110). The legislation provided Bonneville with "self-financing" authority and established the Bonneville Fund, a permanent, indefinite appropriation, allowing Bonneville to use its revenues from electric power and transmission ratepayers to directly fund all programs and to sell bonds to the Treasury to finance the region's high-voltage electric transmission system requirements. In 1980, enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) expanded Bonneville's utility obligations and responsibilities to encourage electric energy conservation; develop renewable energy resources; and protect, mitigate and enhance the fish and wildlife of the Columbia River and its tributaries. In support of these responsibilities, Bonneville's Treasury borrowing authority was expanded to allow the sale of bonds to finance conservation and other resources and to carry out fish and wildlife capital improvements. The Northwest Power Act also required regional energy plans and programs and created the Pacific Northwest Electric Power and Conservation Planning Council, now commonly called the Northwest Power and Conservation Council.

Bonneville's program is treated as mandatory and nondiscretionary. As such, Bonneville is "self-financed" by the ratepayers of the Pacific Northwest and is not annually appropriated by Congress. Under the Transmission System Act, Bonneville funds the expense portion of its budget and repays the Federal investment with revenues from electric power and transmission rates. Bonneville's revenues fluctuate primarily in response to market prices for fuels and stream flow variations in the Columbia River System due to weather conditions and fish recovery needs. Bonneville's permanent statutory borrowing authority authorizes the agency to sell bonds to the Treasury up to a cumulative total of $4.45 billion outstanding at any one time. Through FY 2006, Bonneville has returned approximately $22.7 billion to the Treasury for payment of FCRPS O&M and other costs (about $3.0 billion), interest (about $11.8 billion), and amortization (about $7.9 billion) of appropriations and bonds.

This FY 2008 budget provides that an amount equivalent to net secondary market revenues in excess of $500 million per year are assumed, beginning in FY 2008, to be used to make advance amortization payments to the Treasury on BPA's bond obligations, consistent with both the President's Budget and the sound business practices required under the Federal Columbia River Transmission System Act of 1974. It is the Administration's position that it is sound business practice to use higher-than-historical net secondary revenues to invest back into energy infrastructure and to pay down debt. These advance amortization payments to Treasury will be made consistent with statutory priority of payment requirements.

The Administration believes this action will help to provide BPA with needed financial flexibility to meet its future energy investment needs, including critical transmission capacity. The Administration also believes that long-term power and transmission service customers of BPA should benefit from these advance amortization payments both through lower long-term rates than would otherwise be the case and through improved and upgraded capital facilities. The Administration encourages a continued ongoing dialogue in the Pacific Northwest to address the manner in which this proposal will improve BPA's ability to meet its long-term capital investment needs with minimal rate impact. The budget reflects a total of $646 million from FY 2008 through FY 2012 from these higher-than-historical net secondary revenues.

Additionally, this FY 2008 budget assumes that Energy Northwest (ENW) will refinance a portion of its debt in calendar year 2008, and that the effects of the anticipated debt optimization refinancing are recognized in FY 2008. The additional cash freed up from future refinancings (estimated to be $147 million in FY 2008, for a total of $260 million in FYs 2008-

2012) is assumed to be used to pay down BPA Federal bond debt. The combined total of BPA's debt optimization efforts and Treasury pre-payments from net secondary revenues is estimated to reduce by $906 million of Treasury borrowing by 2012, which is counted toward BPA's $4.45 billion borrowing authority limit.

Bonneville made its full planned FY 2006 payment of $1,113 million to the Treasury, including $342 million in advanced amortization ($337 million of which was due to BPA's debt optimization program). Total FY 2006 credits applied to the Treasury payment for fish mitigation were about $71 million. For FY 2007, Bonneville plans to pay the Treasury $773 million: $388 million to repay investment principal, $364 million for interest, and $21 million for Associated Project costs and pension and post-retirement benefits. The FY 2008 Treasury payment is currently estimated at $1,090 million. FYs 2007 through 2009 4(h)(10)(C) credits associated with fish recovery are estimated at $85 million annually.

Estimates of interest levels for outyear Treasury payments are based on FY 2007 Power Final Rate Proposal estimates and TS's FY 2006 Rate Case estimates. FY 2007 Bond and Appropriations Interest will continue to be revised based on upcoming capital investments and debt management actions. Amortization estimates, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President's budget. These estimates may change due to revised capital investment plans and actual Treasury borrowing. In addition there are restrictions on the amount of bonds available for BPA pre-payment. In recent years, BPA has made amortization payments in excess of those scheduled in its FERC-approved rate filings resulting in a balance of advance repayment. The cumulative amount of advance amortization payments as of the end of FY 2006 is about $1,802 million. Amortization estimates in this FY 2008 budget include planned amortization amounts in advance of scheduled amortization (due to earlier ENW refinancing) of $57 million, $63 million, and $78 million in FYs 2007 through 2009, respectively, consistent with power rate case documentation.

Starting in FY 1997, Bonneville began direct funding the Reclamation's Pacific Northwest power O&M costs, and in FY 1999 Bonneville began direct funding Corps Pacific Northwest power O&M costs. Bonneville began direct funding the USFWS in FY 2001 to pay for O&M costs of the Lower Snake River Compensation Plan facilities. Bonneville's direct funding arrangement includes a portion of power O&M capital investments. Direct funded capital costs, previously funded through appropriations, are now being paid through BPA borrowing from the Treasury. BPA's total O&M direct funding, including the small capital program, was $230 million in FY 2006.

This FY 2008 budget proposes Bonneville accrued expenditures of $2,608 million for operating expenses, $77 million for Projects Funded in Advance, $538 million for capital investments, and $685 million for capital transfers in FY 2008. The budget has been prepared on the basis of Bonneville's major areas of activity, power and transmission. This business structure arose as a response to the 1992 Energy Policy Act and ensuing FERC Orders 888 and 889 requiring separation of utilities' power and transmission functions. As a Federal agency, Bonneville is not subject to FERC's jurisdiction (except for the new requirements of the Energy Policy Act of 2005) but chooses to voluntarily comply with FERC open-access policy. Further, Bonneville supports DOE's October 1995 "Power Marketing Administration Open Access Policy which states the Power Marketing Administrations' commitment to offer transmission services to eligible entities in a manner comparable to the services offered by FERC-jurisdictional transmission providers to the extent not otherwise inconsistent with Federal law.

Spending levels in this budget are still subject to change to accommodate competitive dynamics in the region's energy markets, debt optimization strategies, and the continued restructuring of the electric industry.

- Bonneville's FY 2008 budget reflects the significant financial and business events that have shaped Bonneville's response to the physical and competitive pressures of the region's electricity environment. BPA is striving to enhance its competitive, cost-effective delivery of utility products and services and continued delivery of the public benefits of its operations, while ensuring its ability to make its payments to the Treasury on time and in full. BPA utilizes a strategic planning process using the balanced scorecard model to align all business units around specific goals and align resources to achieve these goals. In support of strengthening its strategic alignment, BPA also seeks to achieve operational efficiencies through a stronger overall agency perspective while still complying with the FERC Standards of Conduct. Additionally, BPA continues to recognize PART feedback from OMB in the areas of planning, performance measurement, and results and marketing. From these efforts, results include continued efficiency gains, performance integration improvements, and a high assurance for repayment of Treasury borrowing.

- After several years of sustained effort, BPA has recovered from the financial effects of the 2000-2001west coast power crisis. FY 2006 results, including better than expected surplus power sales, improved market conditions, cost reductions, debt optimization results, and cost recovery rate adjustment tools have all contributed to help stabilize Bonneville's finances. These gains are helping BPA continue its efforts to assure full recovery of its costs and to assure long-term financial stability while meeting its overall responsibilities to the Pacific Northwest and the U.S. taxpayer. Additionally, BPA is well positioned as it moves into the FY 2007-2009 power rate period.

- BPA conducted an extensive consultation process with stakeholders on its power cost structure for the 2007 through 2009 power rate period. This process, called a Power Function Review (PFR), gave the region the opportunity to examine and provide input on the cost projections that formed the basis for BPA's 2007-2009 power rates. The PFR helped BPA identify total estimated rate period savings forecasted to be $122 million per year.

- BPA submitted its FYs 2007-2009 power rate to FERC in August 2006 and received interim approval of the new rates that took effect October 1, 2006. The power rates include adjustment mechanisms based on the previous year's financial results. Also included is a risk mitigation tool, or "Flexible PF Rate Program" which allows BPA to increase on short notice the amount charged cooperating customers in one month in return for lower charges in subsequent months. The new power rate for most of BPA's customers is lower by about 3 percent from 2006.

- In anticipation of establishing transmission rates for the FY 2006-2007 period, BPA initiated Programs in Review (PIR), a separate public process with customers, constituents and others designed to share proposed transmission program funding levels. Results from the PIR process served as the basis for development of costs in BPA's final 2006-2007 transmission rate proposal and Record of Decision issued in June 2005. The transmission rates were approved by FERC in September 2005.

  The 2006 PIR public process is assisting BPA to establish planned spending levels prior to the upcoming transmission rate case for FYs 2008 and 2009. By 2008, BPA intends to align its transmission and power rate cases and consolidate its public processes on agencywide expenses and capital plans as part of its efforts to increase transparency for customers and stakeholders. The 2006 PIR focuses on operational improvements emphasizing efficiency and effective cost management. Asset management models to enhance operational decisions to maintain reliability are utilized. BPA has negotiated agreement with transmission customers and customer representatives on a settlement of the initial Proposal for the 2008-2009 transmission rates and in January 2007 issued a letter finalizing the proposed funding levels.

- In addition to the program review processes specific to power and transmission, BPA initiated an overview of its long-term projected capital spending agency wide. The targeted goal of this public process during the summer of 2006 was to increase stakeholder understanding of BPA's overall management of its capital programs, including investments in electric facilities, conservation, fish and wildlife, information technology, and transmission.

- Bonneville is continuing efforts to help meet the region's long-term power and transmission infrastructure needs. Bonneville is planning infrastructure investments in the Pacific Northwest to meet Northwest transmission needs that will also continue to support a competitive wholesale market in the Western Interconnection that encompasses 14 western States, two Canadian provinces and one Mexican State. These efforts will help to buffer against escalating fossil fuel prices. BPA continues to target transmission investments in those areas with reliability needs.

- Bonneville has identified a number of actions that it is taking or could take over the next several years to provide additional electric system infrastructure relief. These actions include Federal hydro generation efficiencies and additions, additional renewable resource generation and conservation efforts, long-term and short-term power purchases, and construction of transmission projects that reinforce the grid and integrate new generation. As part of these efforts, Bonneville has designed a process to review and approve certain proposed FCRPS investments.

- Bonneville received an additional $700 million in available Treasury financing through the FY 2003 Appropriations Act to help assure a sufficient level of infrastructure planning. For efficient use of this newly available Treasury financing, BPA will encourage private-sector or other non-Federal financing or joint financing of transmission line expansions and additions, develop a five-year investment plan with the participation of the regional Infrastructure Technical Review Committee or its successor in the region, continue to use funds only for authorized purposes, continue to include the proposed use of the funds in its annual budget submissions and select projects based on cost-effectiveness criteria for achieving the objective. The FY 2003 Appropriations Act increases to $4.45 billion the aggregate amount of bonds Bonneville is authorized by statute to sell to the Treasury and have outstanding at any one time.

- Bonneville considers other strategies to sustain funding for its infrastructure investment requirements as well. These additional strategies include optimization of ENW debt, revenue financing of some amount of transmission investments, and seeking, when feasible, third party financing sources. BPA currently estimates joint financing and ownership (lease-purchase excluding financing for Columbia Generating Station (CGS) new investments) at $100 million in FY 2007, $49 million in FY 2008, $50 million in FY 2009, $50 million in FY 2010, $53 million in FY 2011, and $60 million in FY 2012 for an estimated total of $362 million during the period FY 2007 through FY 2012. Current estimates for CGS new investments which are owned and operated by ENW are $27.5 million, $25.6 million, $27.7 million, $52.9 million, $24.1 million, and $60.3 million for FYs 2007-2012, respectively. This FY 2008 budget assumes $15 million of annual revenue financing in FYs 2006-2009 for transmission infrastructure capital that is included in this budget in Projects Funded In Advance.

- This FY 2008 budget includes capital and expense estimates for PS based on forecasts in the FY 2007 Final Power Rate proposal, and associated outyear estimates for FYs 2010-2012. TS capital and expense estimates are based on forecasted 2006 Transmission Rate Case estimates updated for known changes for FY 2007, PIR estimates for FYs 2008-2009, and associated outyear estimates for FYs 2010-2012. The PIR estimates in this FY 2008 budget do not predetermine final PIR assumed spending levels.

- Capital funding levels also reflect BPA's Capital Planning Review process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region, and national energy security goals. Capital investment levels in this FY 2008 budget also reflect executive management decisions from BPA's cross-agency Capital Allocation Board. FY 2006 costs are based on BPA's FY 2006 audited actual financial results.

- The FYs 2006-2012 revenue estimates in this budget, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools; for example, upcoming rate adjustment mechanisms, reduced cost estimates, a net revenue risk adjustment, debt management strategies, and/or short-term financial tools to manage net revenues and cash. FY 2006 revenue estimates are based on BPA's FY 2006 audited actual financial results.

- Beginning in FY 2008, revenue estimates in this FY 2008 budget include assumed annual net secondary power revenues that exceed $500 million. Actual net secondary revenues would vary significantly due to many variables affecting BPA's revenues including the volatility of secondary power markets and the variability of annual streamflows.

- Revenue calculations include depreciation and 4(h)(10)(C) credit assumptions. These credits offset BPA's fish and wildlife program costs allocable to the non-power project purposes of the FCRPS, consistent with the Northwest Power Act. FYs 2007-2009 credits for 4(h)(10)(C) included in this FY 2008 budget are estimated at $85 million annually. Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that, along with actual market conditions, will impact revenues and expenses.

- Bonneville's efforts to keep its rates as low as possible are augmented by the implementation of the Bonneville Appropriations Refinancing Act (part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996) that refinanced Bonneville's outstanding repayment obligations on appropriations. The legislation called for raising low interest rates on historic appropriations to current Treasury market rates and resetting the principal of unpaid FCRPS appropriations. As called for in the legislation, Bonneville submitted its calculations and interest rate assignments implementing the refinancing to the Treasury. The Treasury then approved the BPA submission in July 1997, thus finalizing the implementation of the Bonneville Appropriations Refinancing Act refinancings.

- The Northwest Power Act created the REP to extend the benefits of low-cost Federal power to the residential and small farm customers of Pacific Northwest electric utilities that meet certain conditions. The 1996 Comprehensive Regional Review (Comprehensive Review) recommended that Bonneville engage in settlement discussions regarding the REP. Bonneville then developed a Subscription Strategy based on the recommendations of the Comprehensive Review. That strategy proposed a comprehensive settlement of the REP for IOUs in the Pacific Northwest, which has resulted in new contracts with regional IOUs that provide monetary benefits to their residential and small farm customers.

  Bonneville's preference utilities, or public agency utilities, have been eligible to execute new REP contracts since October 2001, except for the nine utilities that previously executed settlement agreements for terms ending July 1, 2011. One public agency customer has requested a contract for participation in the REP, which resulted in a settlement. Other public agency customers may also request a contract for participation. See the Operating Expenses- Power Services section for additional discussion of the settlement agreements.

- In April 2003, Bonneville entered into a settlement agreement with Enron Corporation (Enron) relating to its associated power sales and purchase agreements. This agreement followed Enron's filing for bankruptcy protection in December 2001 and was approved in advance by the Enron Bankruptcy Court, the U.S. District Court for the Southern District of New York, in March 2003. Under the settlement, a $99 million payment to Enron was paid directly from the Treasury's judgment fund in June 2003. The agreement calls for Bonneville to fully reimburse the Treasury for the judgment funds used plus interest. Bonneville made its final associated payment in full to Treasury in December 2006. Consistent with a memorandum of understanding with the Treasury, Bonneville made interest payments on the outstanding debt to the Treasury's "miscellaneous receipts" account.

- As part of its continuing competitive efforts, Bonneville is working to further optimize debt service costs (often referred to as debt optimization elsewhere in this budget). Bonneville has reached agreement with ENW to pursue refinancing of certain ENW bonds. Bonneville pays the debt service on these bonds under the terms of earlier net billing agreements. A component of the refinancing strategy is to extend the final maturity on the Columbia Generating Station (CGS, formerly WNP-2) debt. In addition, for Projects 1 and 3, some debt currently maturing prior to FY 2013 is being extended into the FY 2013-2018 time period. During FY 2006 a small portion of CGS bonds were extended into FYs 2020-2024 as part of the debt optimization program. Bonneville has committed to ENW to use the reductions in debt service resulting from this extension to amortize Federal debt earlier than currently scheduled, except in the case of an extreme financial emergency. Implementation of the refinancing components will be subject to favorable market conditions and interest rate environment.

- As part of its strategic staffing efforts and implementation of operational efficiency initiatives, Bonneville has shown a downward trend in Full-Time Employee (FTE) levels since FY 2003. BPA expects its succession planning efforts and continuing efficiency initiatives in targeted areas to level out FTE at about 3,000 in the outyears. BPA continues to pursue various authorities, including the use of voluntary separation incentives (VSI) and voluntary early retirement authority (VERA) to help achieve targeted levels. Annual Bonneville FTE projections included in this FY 2008 budget for FYs 2007 and 2008 are 3,000.

- Bonneville is committed to continue funding its share of the region's efforts to recover listed Columbia Basin fish and wildlife. To the extent possible, Bonneville is integrating the actions implemented in response to the FCRPS Biological Opinions with projects implemented under the Council's Fish and Wildlife Program. Recently completed Sub-basin Plans that include prioritized strategies for mitigation actions will help guide project selection to meet both BPA's ESA and Northwest Power Act responsibilities.

- Discussion of a minimum cost-sharing requirement for fish and wildlife projects funded by BPA in 2007 and beyond is continuing in ongoing discussions with the Council and the regional fish and wildlife managers and Northwest Tribes. As part of these discussions for the Integrated Fish and Wildlife Program, BPA has recommended a reorientation and transition of the program over FY's 2007 – 2009 that places greater emphasis on projects that are performance based and deliver more results on-the ground. On-the ground results include habitat protection, enhancement, tributary passage, screening and hatchery efforts. Recommended guidelines are 70 percent of overall program funding for on-the-ground projects; 25 percent to research, monitoring and evaluation (RM&E); and 5 percent for coordination, data management and administration.

- Consistent with the PFR, this FY 2008 budget sets an estimated Fish and Wildlife program level of $36 million in capital and $143 million in expense for FYs 2007 – FY 2009. These estimates, as well as those for other Bonneville fish program costs may change, however, depending upon evolving circumstances including the long-term effect of Federal court decisions on the NOAA Fisheries 2004 Biological Opinion (2004 BiOp) and the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion.

- Many of the actions in the FCRPS Biological Opinions and the Council's program overlap, particularly in the areas of habitat and hatchery offsite mitigation measures. The FCRPS Action Agencies' (Corps, Reclamation, and Bonneville) Biological Opinion Implementation Plans describe an approach that maximizes the use of the Council's regional processes to identify and select projects that avoid jeopardizing the survival of the ESA-listed species and to protect, mitigate and enhance fish and wildlife; both listed and non-listed affected by the operation of the FCRPS. The Council's Fish and Wildlife Program provides the mechanism for integrating activities focused on ESA-listed fish stocks in the 2004 BiOp and USFWS 2000 and 2006 Biological Opinions for the FCRPS with those for non-listed species affected by the Columbia Basin's Federal and non-Federal hydrosystems. Recently completed Sub-basin Plans that include strategies for mitigation actions will help guide project selection to meet both BPA's ESA and Power Act responsibilities.

- The FY 1997 Energy and Water Development Appropriations Act added section 4(h)(10)(D) to the Northwest Power Act, directing the Council to appoint an Independent Scientific Review Panel (ISRP) "to review a sufficient number of projects" proposed to be funded through Bonneville's fish and wildlife budget "to adequately ensure that the list of prioritized projects recommended is consistent with the Council's program." The NW Power Act further states that ". . . in making its recommendations to Bonneville, the Council shall consider the impact of ocean conditions on fish and wildlife populations; and shall determine whether the projects employ cost-effective measures to achieve program objectives." Consequently, projects funded by Bonneville under the program are reviewed and prioritized as part of the Council recommendation process.

- Included with the budget schedules section of this budget document is the current tabulation of Bonneville's fish and wildlife costs from FY 1996 through 2006.

President's Management Agenda

- In the area of the President's Management Agenda (PMA), Bonneville is leveraging the President's initiatives to achieve efficiencies while preserving the long-term value of the FCRPS. To ensure that Bonneville is able to fully leverage the initiatives, Bonneville has incorporated a matrix team approach utilizing OMB and the Office of Personnel Management (OPM) "Proud to Be" standards and is continuing to develop strategies to achieve greater efficiencies in Bonneville programs and operations. In 2006, BPA was rated "green" on its performance of each annual target associated with the DOE Energy General Goal.

- Bonneville is self-reporting its Current Status as "green", or successful, on both the Financial Management and the Integrating Budget and Performance initiatives. Over the past several years, Bonneville has streamlined and integrated its strategic planning and budgeting processes, set quantifiable goals and targets, aligned its resource allocations, and implemented the Balance Scorecard concept of performance management. BPA has initiated a "full-cycle financial management" process where the agency's strategic direction drives the development of performance targets that in turn are reflected in outyear budget estimates, BPA's long-term rate development process, and individual managerial performance contracts. BPA continues to coordinate closely with DOE to accommodate accelerated budget and financial results reporting requirements.

  Bonneville has received a clean audit opinion since the mid-1980s and has no material financial weaknesses reported on its financial statements. In addition, BPA has met its FY 2006 target to achieve OMB's Circular A-123 compliance assurance on financial reporting and has issued an unqualified attestation for A-123 compliance for 2006.

  Bonneville planning and budgeting processes include extensive Bonneville stakeholder involvement, including customers, constituents, tribal and other interested parties in the region. Bonneville's financial management systems and reporting procedures meet Federal standards, comply with Generally Accepted Accounting Principles (GAAP), and are consistent with Presidential Initiative schedule guidance.

  Bonneville, along with the Corps and Reclamation, has developed an asset management strategy to improve the performance and efficiency of FCRPS assets. This strategy evolved into a comprehensive integrated business management model, which dovetails with the President's Budget and Performance initiative. In addition, BPA continues to improve its overall agency capital asset management strategy resulting in a more rigorous and analytical based prioritization of capital projects. Asset management models are being utilized to make the right investment and operational decisions to support reliability, cost-effectiveness and efficiency goals.

- In the area of Expanding E-Government, Bonneville is self-reporting its Progress Toward Implementing the President's Management Agenda as "green." Supporting "E-Gov" initiatives, BPA has expanded its participation and efforts in this area and has consolidated its business and administrative Information Technology (IT) groups to gain operating efficiencies and improve overall performance. Bonneville achieves OMB standards for IT business case preparation and for providing improved citizen web access by offering one-stop shopping through integrated delivery methods, while reducing undue burden on our business partners and customers by lessening or eliminating the need to re-key data. Bonneville has developed an Enterprise Resource Planning system that integrates its major business process and provides its managers and employees with access to timely and accurate financial, personnel, and property reports. BPA will continue to work with DOE to expand and strengthen its E-Gov initiative participation.

- Bonneville is self-reporting "green" in Current Status and "green" in Progress toward Implementing the President's Management Agenda in the area of Human Capital. This initiative has served as a catalyst in redefining BPA's organizational strategy, in developing and getting alignment with meaningful objectives, and in assigning clear accountabilities. A 2006 Workforce Plan sets forth BPA's strategy for achieving these goals. The Human Capital Initiative also underscores BPA's efforts toward creating a culture and workforce capability that ensure its ability to successfully achieve its mission.

  In support of these efforts, BPA is also implementing its "position management" initiative that will evaluate the structuring of positions, functions, and organizations in a manner that optimizes productivity, efficiency, and organizational effectiveness. Strong position management will help ensure the efficient distribution of staff resources and help in identifying, preventing, and eliminating unnecessary organizational fragmentation. Implementation of this long-term program will utilize position management targets.

  Through its performance management systems, Bonneville aligned agency strategic business objectives with quantifiable targets that are embedded in individual executive and managerial performance contracts. Development of a new Human Resource Management Information System tool to support organizational development plans focused on closing mission critical skills gaps is underway. Additionally, as a result of efficiency improvement recommendations, developmental cross training programs are being utilized to support succession planning.

Overview of Detailed Justifications

Bonneville's Detailed Justification Summaries, included in this FY 2008 budget, follow present budget requirements for budget line items on the basis of accrued expenditures. Accrued expenditure is the basis of presenting Bonneville's program funding levels in the power and transmission rate making processes and the basis upon which Bonneville managers control their resources to provide products and services. Accrued expenditures relate period costs to period performance. Traditional budget obligation requirements for Bonneville's budget are assumed on the Program and Financing Summary Schedule prepared in accord with OMB Circular A-11.

The organization of BPA's FY 2008 budget and these performance summaries reflect Bonneville's business services basis for utility enterprise activities. Bonneville's major areas of activity on a consolidated budget and accounting basis include power and transmission with administrative costs included. PS includes line items for Fish and Wildlife, Conservation and Energy Efficiency, REP, Associated Projects O&M Costs, and Council. Environmental activities are shown in the relevant power and transmission services, as are reimbursable costs. Bonneville's interest expenses, pension and post-retirement benefits, and capital transfers to the Treasury are shown by program.

The first section of performance summaries, Capital Investments, includes accrued expenditures for investments in electric utility and general plant associated with the FCRPS generation and transmission services, conservation and energy efficiency services, fish and wildlife, and capital equipment. These capital investments will require budget obligations and use of existing borrowing authority of $615 million in FY 2008.

The near-term forecast capital funding levels have undergone an extensive internal review as a result of BPA's Capital Planning Review process and its associated capital asset management strategy. These capital reviews encompass project cost management initiatives, capital investment assessments, and categorization of capital projects to be funded based on risk and other factors. Consistent with BPA's near-term capital funding review process and BPA's standard operating budget process, this FY 2008 budget includes updated capital funding levels for FY 2007. Utilizing this review process helps Bonneville in its efforts to compete in the deregulated energy market. Bonneville will continue to work with the Corps and the Reclamation to optimize the best mix of projects.

In addition to its extensive internal management assessment of capital investments, Bonneville has developed and implemented an associated external capital investment review process that provides significant benefits to Bonneville. The combined internal and external processes add value by both improving direction on what the FCRPS invests in (tying investments more closely to agency strategy) and by improving how those investments are made (better analysis and review of capital investments and their alternatives). BPA will continue its efforts to refine and further implement its capital investment review process to improve the value provided.

Bonneville's second section of the performance summaries, entitled Annual Operating Expenses, includes accrued expenditures for services and program activities financed by power sales revenues, transmission services revenues and projects funded in advance. For FY 2008, budget expense obligations are estimated at $2,608 million. The total program requirements of all Bonneville programs include estimated budget obligations of $3,223 million in FY 2008.

Bonneville Power Administration

Funding Profile by Subprogram 1/

(accrued expenditures in thousands of dollars)

	Fiscal Year				
	2006 Actuals	2007 Original /2	2007 Adjustments	2007 Revised /2	2008 Proposed
Capital Investment Obligations					
Associated Project Costs 3/	120,561	N/A	-	133,000	145,000
Fish & Wildlife	35,414	N/A	-	36,000	36,000
Conservation & Energy Efficiency 3/	20,058	N/A	-	32,000	32,000
Subtotal, Power Services 4/	176,033	N/A	-	201,000	213,000
Transmission Services	138,474			226,821	278,059
Capital Equipment & Bond Premium	17,671	N/A	-	32,785	47,421
Total, Capital Obligations 3/ 5/	332,178	476,793	-	460,606	538,480
Expensed and Other Obligations					
Expensed	2,523,739	2,464,963	-	2,779,011	2,608,506
Projects Funded in Advance	47,917	94,989	-	138,883	77,494
Total, Obligations	2,903,834	3,036,745		3,378,500	3,224,480
Capital Transfers (cash) 5/	696,919	877,573	-	386,541	686,068
BPA Total	3,600,753	3,914,318	-	3,765,041	3,910,548
Full-time Equivalents (FTEs)	2,923	3,000	-	3,000	3,000

Public Law Authorizations include:

Bonneville Project Act of 1937, Public Law No. 75-329, H.R. 7642

Federal Columbia River Transmission Act of 1974, Public Law No. 93-454 S. 3362

Regional Preference Act of 1964, Public Law No. 88-552

Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act), Public Law No. 96-501, S. 885

Outyear Funding Profile by Subprogram 1/

(accrued expenditures in thousands of dollars)

	Fiscal Year 2009	2010	2011	2012
Associated Project Costs 3/	137,000	123,000	124,000	135,000
Fish & Wildlife	36,000	36,000	36,000	36,000
Conservation & Energy Efficiency 3/	32,000	40,000	40,000	40,000
Subtotal, Power Services 4/	205,000	199,000	200,000	211,000
Transmission Services	253,083	281,487	280,900	299,977
Capital Equipment & Bond Premium	32,187	31,363	26,116	27,170
Total, Capital Obligations 3/ 5/	490,270	511,850	507,016	538,147
Expensed and Other Obligations				
Expensed	2,894,485	2,708,216	2,792,553	2,699,924
Projects Funded in Advance	76,557	69,052	71,055	63,616
Total, Obligations	3,461,312	3,289,118	3,370,624	3,301,687
Capital Transfers (cash) 5/	404,408	518,711	468,451	395,886
BPA Total	3,865,720	3,807,829	3,839,075	3,697,573
Full-time Equivalents (FTEs)	3,000	3,000	3,000	3,000

The accompanying notes are an integral part of this table.

1/ This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

2/ Original estimates reflect BPA's FY 2007 Congressional Budget Submission. Revised estimates, consistent with BPA's annual near-term funding review process, provide notification to the Administration and Congress of updated capital and expense funding levels for FY 2007.

3/ Includes infrastructure investments designed to address the long-term needs of the Northwest and to reflect significant changes affecting BPA's power and transmission markets.

4/ Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

5/ This FY 2008 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2012. The TS capital and expense estimates are based on forecasted Transmission 2006 Rate Case estimates updated for known changes for FY 2007, PIR estimates for FYs 2008-2009, and associated outyear estimates for FYs 2010-2012.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Amortization/Capital Transfer estimates in this budget, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President's budget. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and other variables that may affect the opportunity for advanced amortization payments.

The cumulative amount of actual advance amortization payments as of the end of FY 2006 is $1,802 million.

Refer to 16 USC Chapters 12B, 12G, 12H, and BPA's other organic laws, including P.L. 100-371, Title III, Sec. 300, 102 Stat. 869, July 18, 1988 regarding BPA's ability to obligate funds.

Major Outyear Considerations

Bonneville's outyear estimates reflect its ongoing efforts to achieve its long-term mission and strategic direction. The outyear estimates are developed with consideration of and support of BPA's multi-year performance targets that lay out the course for achieving BPA's long-term objectives. Outyear capital investment levels support BPA's infrastructure program, hydro efficiency program, conservation and energy efficiency projects, and its fish and wildlife mitigation projects.

With passage of the recent Energy Policy Act of 2005, Bonneville is now working to incorporate the various aspects of the legislation related to its business, in particular the energy supply, conservation and new energy technologies for the future that are highlighted in the legislation.

Power Services - Capital

Funding Schedule by Activity

(accrued expenditures)
(dollars in thousands)

Power Services - Capital	FY 2006	FY 2007	FY 2008
Associated Project Costs	120,561	133,000	145,000
Fish & Wildlife	35,414	36,000	36,000
Conservation & Energy Efficiency	20,058	32,000	32,000
Total, Power Services - Capital	176,033	201,000	213,000

Outyear Funding Schedule

(accrued expenditures)
(dollars in thousands)

	FY 2009	FY 2010	FY 2011	FY 2012
Total, Power Services - Capital.	205,000	199,000	200,000	211,000

Description

Associated Project Costs provide for direct funding of additions, improvements and replacements of existing Reclamation and Corps hydroelectric projects in the Pacific Northwest that provide for increased performance and availability of generating units. The Reclamation and Corps hydro projects produce electric power which is marketed by Bonneville.

Maintaining the availability and increasing the efficiency of the FCRPS is critical to ensuring that the region has an adequate, reliable and low-cost power system. The FCRPS represents about 80 percent of Bonneville's power supply and is composed of 31 operating Federal hydro electric projects with over 200 generating units. These projects have an average age of over 45 years, with some that exceed 60 years of age. Through direct funding and the close cooperation of the Corps and Reclamation, Bonneville uses its borrowing authority to make investments needed to restore generation availability and improve efficiency, reducing demand on Corps and Reclamation appropriations for power-related investments. Since the beginning of direct funding, Bonneville along with its joint operating partners, the Corps and Reclamation, have significantly improved system performance. In 1999, at the direction of Congress, Bonneville issued a report that it soon began to implement called the "Asset Management Strategy for the FCRPS." Bonneville concluded in this report that it needed to invest nearly $1 billion in the projects over the next 12-15 years. Without these investments, that are focused on restoring and maintaining the reliability of the system, history indicates that unit availability may initially decline at a rate of about 1.5 percent per year. Supplementary analyses and experience with the system have revealed additional investment needs above and beyond the levels originally planned under the Asset Management Strategy for this and the next several rate periods.

These planned investments, included in this FY 2008 budget funding estimates, will maintain the output of the FCRPS. Moving forward with these cost-effective opportunities to expand the generation and to preserve and enhance the capability of the Federal system is a smart economic and environmental decision when compared to purchasing power from the market to serve Pacific Northwest electricity needs.

The Fish and Wildlife program provides for the protection, enhancement and mitigation of Columbia River Basin fish and wildlife due to losses attributed to the development and operation of the Federal hydroelectric projects on the Columbia River and its tributaries from which Bonneville markets power, pursuant to Section 4(h) of the Northwest Power Act. Bonneville satisfies a major portion of its fish and wildlife responsibilities by meeting the Administrator's obligation under the Council's Fish and Wildlife Program.

Bonneville is also mandated to implement measures called for under the ESA. These measures are part of the most recent biological opinions issued in November 2004 by the NOAA Fisheries and in 2000 and 2006 by the USFWS to address the effects of the operation of the FCRPS on threatened and endangered salmon and steelhead and ESA-listed Kootenai River white sturgeon and bull trout. The biological opinions require the FCRPS Action Agencies to implement actions in the Columbia River Basin that address impacts of the Federal hydrosystem on ESA-listed fish to ensure that operation of the FCRPS does not jeopardize the continued existence of listed species or adversely modify their designated critical habitat. In February 2005, the FCRPS Action Agencies published an implementation plan for their proposed action addressed in the 2004 BiOp. The implementation plan, together with projects undertaken to address mitigation for non-listed species under the Northwest Power Act, and those to address requirements of the USFWS 2000 and 2006 Biological Opinion form the basis for Bonneville's planned capital investment of $36 million for FYs 2007 and 2008.

The 2004 BiOp was challenged in Federal District Court. In October 2005, the District Court invalidated the 2004 BiOp, although leaving it "in place" during the remand period. The Judge also ordered the sovereign parties to collaborate during the remand process, to try to find an acceptable approach for the 2004 BiOp that would have regional support. In December, the Department of Justice filed a notice to appeal the District Court's October 2005 remand order. However, the Federal parties continue to support the court ordered collaboration on the 2004 BiOp, even though an appeal has been filed. In response to litigation seeking injunctive relief on the FCRPS in 2006, the Court approved the Federal spill plan with two modifications. In 2006 (the timeframe of the injunction), the FCRPS continued to spill during late spring and late August. The 2007 spill plan largely repeats the 2006 plan. The remand is now scheduled to be completed by July 2007.

There has also been litigation directed at the USFWS Biological Opinions for Libby dam. In 2003, the Corps and BPA reinitiated consultation on the operations at Libby dam to address impacts to recently designated critical habitat for the Kootenai River white sturgeon, and to evaluate information that had been developed on the Kootenai River white sturgeon and bull trout since the 2000 USFWS BiOp. That consultation was completed in February 2006, but has now been challenged by environmental groups, the Kootenai Tribe, and the State of Montana in the Federal district court of Montana.

Bonneville's fish and wildlife capital program is directed at activities that increase numbers of Columbia River Basin fish and wildlife resources including projects designed to increase juvenile and adult fish passage in tributaries and at mainstream dams, and increase fish production and survival through construction of hatchery and acclimation facilities, land acquisitions for resident fish and wildlife that are consistent with Bonneville's Capital Policy, and fish monitoring facilities. Capital project funding will focus on integrating ESA-related priorities with the Council's Fish and Wildlife Program.

The FY 1997 Energy and Water Appropriations Act added section 4(h)(10)(D) to the Northwest Power Act, directing the Council to appoint an ISRP "to review a sufficient number of projects" proposed to be funded through Bonneville's fish and wildlife budget "to adequately ensure that the list of prioritized projects recommended is consistent with the Council's program." The Northwest Power Act further states that " . . . in making its recommendations to Bonneville, the Planning Council shall consider the impact of ocean conditions on fish and wildlife populations; and shall determine whether the projects employ cost effective measures to achieve program objectives." The Conference Report on the FY 1999 Energy and Water Development Appropriations Act included a new assignment for the ISRP and the Council. The ISRP was to review the fish and wildlife projects, programs, or measures included in Federal agency budgets that are reimbursed and/or directly funded by Bonneville and to make funding recommendations to Congress. The ISRP was directed to determine whether the proposals are consistent with the scientific criteria in the Northwest Power Act as amended in 1996, and to provide a report to the Council by April 1 of each year. The Council, in turn, must report to Congress annually by May 15.

The Federal Caucus, a group of eight agencies operating in the Columbia River Basin that have natural resource responsibilities related to ESA, released in December 2000 a comprehensive long-term strategy to restore ESA-listed fish throughout the Columbia Basin. This strategy includes the "All-H" paper that focuses on the establishment of explicit, scientifically based performance standards to gauge the status of salmon and the success of recovery efforts. Consistent with the principles of the All-H Strategy, Bonneville is implementing much of the off-site mitigation actions required by the FCRPS Biological Opinions through the Council's Fish and Wildlife Program.

Under the 1980 Northwest Power Act, the Fish and Wildlife Program is tasked with protecting, mitigating and enhancing Columbia River Basin fish and wildlife affected by any hydroelectric project in the basin. The Council's Fish and Wildlife Program provides the mechanism for integrating activities focused on ESA-listed fish stocks in the 2004 BiOp and USFWS 2006 Biological Opinions for the FCRPS with those for non-listed species affected by the Columbia Basin's Federal and non-Federal hydrosystems. Recently completed Sub-basin Plans that include strategies for mitigation actions will help guide project selection to meet both BPA's ESA and Power Act responsibilities. Additionally, discussion of a minimum cost-sharing requirement for fish and wildlife projects funded by BPA in 2007 and beyond is continuing in currently ongoing discussions with the Council and the regional fish and wildlife managers and Tribes. BPA established a Cost-Sharing Memorandum of Understanding with the US Forest Service in FY 2007 that requires a programmatic 30 percent cost share for fish and wildlife mitigation projects funded by BPA on US Forest Service lands.

As part of these discussions for the Integrated Fish and Wildlife Program, BPA has recommended a reorientation and transition of the program over FY's 2007 – 2009 that places greater emphasis on projects that are performance based and deliver more results on-the ground. On-the ground results include habitat protection, enhancement, tributary passage, screening and hatchery efforts. Recommended guidelines are 70 percent of overall program funding for on-the-ground projects; 25 percent to RM&E; and 5 percent for coordination, data management and administration. Consistent with the PFR, this FY 2008 budget sets an estimated program level of $36 million in capital and $143 million in expense for FYs 2007 – FY 2009. These estimates as well as those for other Bonneville fish program costs may change, however, depending upon evolving circumstances including the long-term effect of the Federal district court decision on the 2004 BiOp and the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion.

When acquiring resources to meet planned future loads, the Northwest Power Act requires the Administrator to first consider and acquire cost-effective conservation that the Administrator determines is consistent with the Northwest Power and Conservation Council's Power Plan. The Council's most recent Power Plan, finalized in January 2005, defines conservation as the more efficient use of electricity and recommends that the region develop 700 aMW of conservation over the next 5-years. Bonneville's share of the conservation target is 40 percent or 280 aMW. Bonneville anticipates that between 100 and 150 aMW of this amount will be acquired under its capital conservation acquisition program. Program performance measurements ($/aMW) indicate that Bonneville is getting excellent value for these investments as benchmarked against other utilities across the nation.

Conservation was key to the recent effort to reduce Bonneville's power delivery obligations as a way of limiting the impact of volatile and high market prices on Bonneville's rates. Conservation is an important part of Bonneville's diverse portfolio of resources that provides a reliable approach to meeting Bonneville's load obligations.

Long-term investments in energy efficiency help buffer the FCRPS against future resource uncertainties. During periods of price volatility, conservation also helps reduce financial risk associated with relying on the market for energy purchases in the future.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Associated Project Costs	**120,561**	**133,000**	**145,000**

BPA will work with both the Corps and Reclamation to reach mutual agreement on those capital improvement projects that need to be budgeted and scheduled, are cost-effective and provide system or site-specific enhancements, increase system reliability, or provide generation efficiencies.

The work is focused on improving the reliability of the FCRPS, increasing its generation efficiency through turbine runner replacements and optimization of hydro facility operation, and small capital reimbursements associated with routine maintenance activities. Also, limited investments may be made in joint use facilities that are beneficial to both the FCRPS operations and to other Corps and Reclamation purposes.

(dollars in thousands)		
FY 2006	FY 2007	FY 2008

- **Corps of Engineers (known projects to date)**

FY 2006: Completed work on Power System Reliability Improvements on Lower Snake River projects. Continued main unit and station service breaker replacements at selected projects. Continued work on oil/water separators at most projects. Continued hydro optimization investigations and equipment installations at selected projects. Continued work on governor replacements at selected projects. Continued refurbishment/replacement of head gates, and completed rehabilitation of bridge crane and replacement of gantry crane at Bonneville. Began exciter installation and DC and preferred AC upgrades at Bonneville Powerhouse 2. Continued rehabilitation work at Bonneville. Continued HVAC upgrade and replacement of unwatering pumps at Bonneville. Continued turbine runner replacement and plant modernization at McNary. Completed exciter replacements at John Day and Willamette Valley projects. Completed plant upgrade and turbine replacement at Cougar. Continued exciter replacements at Libby. Continued CO_2 system replacement at Chief Joseph. Completed station service transformer replacement at Chief Joseph. Completed evaluating turbine replacements at Chief Joseph and began solicitation for new runners. Began design for exciter replacements at Chief Joseph. Continued crane rehabilitation at Chief Joseph and Ice Harbor. Continued purchase of replacement generator windings for Lower Granite and Detroit. Completed replacement of exciters at Lower Monumental and Lower Granite. Completed or continued replacement and upgrades on protective relays and fire protection at Lower Snake River projects. Completed heat pump replacements at Little Goose. Began purchase of spare or replacement transformers for several projects. Continued intake crane rehabilitation and station service improvements at The Dalles. Continued rehabilitation work at The Dalles. Completed installation of replacement transformer for failed unit at The Dalles. Began fire protection design and disconnect replacement at The Dalles. Began fire protection design for Willamette Valley projects. Continued butterfly valve control replacement at Hills Creek, plus a variety of smaller continuing or new investments and repairs to failed units.

FY 2007: Continue work on Power System Reliability Improvements, specifically Generic Data Acquisition and Control System installations at Albeni Falls and Intercontrol Center Communications Protocol improvements at most projects. Continue pursuing remote operation at Albeni Falls and Libby. Continue main unit and station service breaker replacements at selected projects. Continue work on oil/water separators at most projects. Continue hydro optimization development at several projects. Continue work on governor replacements at selected projects. Continue refurbishment/replacement of head gates at Bonneville. Begin last generator rewedging at Bonneville, Powerhouse 2. Continue exciter replacements and, DC and Preferred AC upgrades at for Bonneville, Powerhouse 2. Continue rehabilitation work at Bonneville, Powerhouse 1.

Complete HVAC upgrade and replacement of unwatering pumps at Bonneville. Continue turbine runner replacement and plant modernization at McNary. Complete exciter replacements at Libby. Continue CO2 system installation at Chief Joseph. Continue work on the supervisory control consoles replacements at Chief Joseph. Complete crane rehabilitation at Chief Joseph. Continue turbine replacement project at Chief Joseph. Continue exciter replacements at Chief Joseph. Continue crane repair, generator replacements and electric reliability upgrades at Detroit. Finish remote control installation at Detroit. Complete 480 volts switchgear replacement at Dworshak. Continue purchase and replacement of generator windings at Lower Granite.

Continue replacement and upgrades of protective relays and fire protection at Lower Snake River projects. Complete elevator rehabilitation at Little Goose and Lower Monumental. Complete intake crane rehabilitation at Lower Monumental. Continue purchase of spare draft tube bulkhead for lower Snake plants. Continue head gate rehabilitation at McNary. Continue replacement transformer efforts for several projects. Continue turbine evaluation and replacement at Lookout Point. Complete turbine linkage repair at John Day. Continue bridge crane rehabilitation at John Day. Continue intake crane rehabilitation and station service improvements at The Dalles. Continue rehabilitation work at The Dalles. Continue fire protection design and disconnect replacement at The Dalles. Continue fire protection design and replacement at John Day and Willamette Valley projects. Completed butterfly valve control replacement at Hills Creek, plus a variety of smaller continuing or new investments and repairs to failed units.

FY 2008: Continue pursuing remote operation at Albeni Falls and Libby. Complete main unit and station service breaker replacements at selected projects. Continue work on oil/water separators at selected projects. Continue work on governor replacements at selected projects. Continue refurbishment/replacement of head gates and gantry cranes at Bonneville. Complete last generator rewedging at Bonneville, Powerhouse 2. Continue exciter replacements and complete DC and Preferred AC upgrades at for Bonneville, Powerhouse 2. Continue rehabilitation work at Bonneville, Powerhouse 1. Complete HVAC upgrade and replacement of unwatering pumps at Bonneville.

Continue turbine runner replacement and plant modernization at McNary. Complete CO2 system installation at Chief Joseph. Begin work on the 480-volt distribution system at Chief Joseph. Continue turbine replacements at Chief Joseph. Continue exciter replacements at Chief Joseph. Complete generator replacements and electric reliability upgrades at Detroit. Complete purchase and replacement of generator windings at Lower Granite. Continue purchase of spare draft tube bulkhead for lower Snake plants. Continue head gate rehabilitation at McNary. Continue turbine replacement at Lookout Point. Complete crane rehabilitation at Lookout Point. Continue fire protection replacement at John Day. Complete bridge crane rehabilitation at John Day. Continue rehabilitation work, disconnect work and station service improvements at The Dalles, plus a variety of smaller continuing or new investments and repairs to failed units.

(dollars in thousands)		
FY 2006	FY 2007	FY 2008

Bureau of Reclamation (known projects to date):

FY 2006: Continued Grand Coulee runner replacements. Completed main unit breaker replacement at Grand Coulee. Continued air housing cooler replacement at Grand Coulee. Completed modifications to Grand Coulee Arrival Center. Continued breaker and switchgear replacements at Grand Coulee. Completed replacement of air compressors at Grand Coulee. Purchased another spare winding for Grand Coulee. Continued hydro optimization investigations and equipment installations at Grand Coulee. Continued SCADA replacement at Grand Coulee and Hungry Horse. Continue river bank monitoring system and station service transformer replacements at Grand Coulee. Completed life-safety modifications at Hungry Horse. Continue exciter replacement at Anderson Ranch. Continued transformer replacements at Green Springs and Roza. Continued DC upgrade at Palisades. Continued seal ring replacement at Chandler, plus a variety of smaller continuing or new investments and repairs to failed units.

FY 2007: Continue Grand Coulee runner replacements. Continue air housing cooler replacement at Grand Coulee. Continue breaker and complete switchgear replacements at Grand Coulee. Continue hydro optimization investigations and equipment installations at Grand Coulee. Continue SCADA replacement at Grand Coulee and Hungry Horse. Complete river bank monitoring system and station service transformer replacements at Grand Coulee. Begin elevator rehabilitation and roof replacements at Grand Coulee. Continue station service breakers replacements at Hungry Horse. Completed exciter replacement at Anderson Ranch. Continue transformer replacements at Green Springs and Roza. Complete DC upgrade at Palisades. Complete seal ring replacement at Chandler, plus a variety of smaller continuing or new investments and repairs to failed units.

FY 2008: Continue Grand Coulee runner replacements. Continue air housing cooler replacement at Grand Coulee. Continue breaker replacements at Grand Coulee. Complete elevator rehabilitation and roof replacements at Grand Coulee. Complete hydro optimization investigations and equipment installations at Grand Coulee. Continue SCADA replacement at Grand Coulee and Hungry Horse. Complete station service breaker replacements at Hungry Horse. Complete transformer replacements at Green Springs and Roza, plus a variety of smaller continuing or new investments and repairs to failed units.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Fish and Wildlife	**35,414**	**36,000**	**36,000**

Although the Sub-basin planning effort resulting in management strategies and priorities for projects to be recommended for funding in FY 2008 is complete, specific project solicitation and funding decisions will not be completed until late fall 2007. Therefore, based upon priorities and strategies described in the completed subbasin plans, the following projects may be candidates for capital funding in FY 2008. It is Bonneville's intention to proceed with design, environmental review, and construction of those projects from this list and that are recommended for funding within the available budget. The costs indicated are preliminary estimates only and actual costs may be greater or lower than those estimates, depending on final environmental review decisions and design and construction costs.

The following fishery facilities have been submitted for Congressional approval for FY 2008 as authorized by the Pacific Northwest Electric Power and Planning Act for new fish and wildlife facilities of $1 million and an economic life greater than 15 years (PL 96-501, sec.4.(H)(10)(B)): Lower Granite Dam fish trap, the Kootenai River White Sturgeon Hatchery, the Nez Perce Tribal Hatchery, Redfish Lake Sockeye Captive Brood expansion, hatchery production facilities to supplement Chinook salmon below Chief Joseph Dam in Washington, Hood River Production Facility, Klickitat production expansion, Mid Columbia Coho restoration, and Yakama Coho restoration. See Proposed Appropriations Language included earlier in this FY 2008 budget.

These facilities are based upon the best science and are regionally important in that they provide high priority mitigation and recovery actions for fish and wildlife populations as affected by the FCRPS, under the auspices of the Northwest Power Act and the Endangered Species Act. Projects listed below deliver direct on-the-ground benefits to both ESA listed and non listed fish and wildlife throughout the Columbia River Basin and have been evaluated and coordinated with the Northwest Power and Conservation Council, State, Federal and Tribal fishery resource managers, local governments, watershed and environmental groups and other interested parties.

FY 2006-2008 efforts include continued implementation of high priority ESA-related projects and activities associated with the 2004 BiOp and USFWS 2000 and 2006 Biological Opinions and amended FCRPS Action Agency proposal, consistent with the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion. Implementation of reforms to hatchery programs that help reduce impacts upon ESA-listed populations may also be warranted as information on the types of changes to these facilities are established and priorities for sequencing implementation are developed. Projects that implement the NOAA Fisheries 2004 and USFWS 2006 Biological Opinions are also described in the updated FCRPS Action Agencies' Implementation Plans. Bonneville may include capitalization of investment in land acquisition for fish and wildlife provided such costs exceed $1 million, such investment provides a creditable and quantifiable benefit against a defined obligation for Bonneville, and is consistent with Bonneville's Capital Policy.

(dollars in thousands)

FY 2006	FY 2007	FY 2008

The five types of capital projects as defined by the FY 2007 Power Rate Case are as follows:

1) ***Tributary passage*** -- Activities that enhance fish passage to tributary rivers. For the purpose of this policy, a tributary is defined by the Council designated sub-basin of the tributary. Functionally interdependent work elements could contain the following: wells, ladders, screens, pumping, culverts, diversion (irrigation) consolidation, piping to reduce water loss, irrigation efficiencies (drip irrigation), lining of ditches (seepage reduction), removal of damming objects or pushup dams in conjunction with related construction, and construction related habitat restoration.

2) ***Gas abatement*** -- Projects that reduce or eliminate the super-saturation of gaseous nitrogen in water beneath the dam spillways.

3) ***Hatchery facility construction*** -- Projects and activities relating to the construction of fish hatcheries, including related satellite facilities (acclimation ponds). This may also include construction-related habitat restoration.

4) ***Mainstem passage*** -- Projects and activities which benefit fish passage in the mainstem of Columbia River or Snake River. Capital projects include: ladders, removable spillway weirs, collection facilities, PIT tag facilities, etc.

5) ***Land acquisition*** -- Land acquisition projects protect, enhance, and maintain instream wetland and riparian habitat and provide habitat units (HU's) for wildlife and instream miles for resident fish to fulfill the legal obligation of FCRPS.

Anadromous fish supplementation, production and related facilities, and/or juvenile and adult passage improvement projects that may require capital funds in FY 2008 include the following:

- Yakima River Spring Chinook Supplementation Facility, located in Cle Elum, Washington: This project includes the construction of an interpretive building for public education and for the design and construction of a monitoring and evaluation building at Nelson Springs for use by project biologists.

-Snake River Spring Chinook Salmon artificial propagation facilities (known as the Northeast Oregon Hatchery or NEOH), to be located on the Upper Grande Ronde River near La Grande, Oregon, on Catherine Creek near Union, Oregon, and on Lostine River near Enterprise, Oregon: The design and construction is expected to continue. This project, as a measure in the Council's Fish & Wildlife Program, would also identify and develop artificial propagation facilities to protect and enhance salmon and steelhead native to the Imnaha and Grande Ronde River Basins.

(dollars in thousands)		
FY 2006	FY 2007	FY 2008

-Lower Granite Dam fish trap. Redesign the trap facility to improve capability of broodstock collection. The objective is to improve collection of Endangered Snake River spring and fall Chinook broodstock in response to mitigation under the NOAA Fisheries FCRPS 2004 Biological Opinion. This is a Federal Action Agencies Updated Proposed Action project.

This project, as part of the smolt monitoring program (SMP), provides important information on salmon and steelhead movement at the upper end of the Snake River's series of dams. Fish PIT-tagged at these sites are used to measure migration speed in key reaches of the Snake and Columbia rivers. The determination of the current year's migration timing of ESA-listed Snake River salmonid stocks is a key aspect of the year's in-season SMP management decisions. This information is critical for in-season management decisions relative to operations of the FCRPS for fish protection, flow augmentation, facility power operations, fish collections, and transportation programs.

-Kootenai River Hatchery. The Kootenai River sturgeon hatchery in Idaho is in need of hatchery upgrades and expansion to improve temperature control and rearing conditions that will result in the increased overall survival of these ESA-listed fish after release from this facility. In addition this may also include development of a burbot production facility to offset the loss of natural production below Libby Dam. The project requires development and review of a Master Plan prior to implementation. Fish and wildlife resources in the Kootenai drainage were historically abundant and were used by the Kootenai Tribe for cultural and subsistence purposes. Over the past decades, native fish and wildlife populations have declined significantly due to large-scale habitat and ecosystem changes. Native kokanee from the South Arm of Kootenay Lake are considered "functionally extinct," burbot from the lower Kootenai River are on the verge of extinction, and the white sturgeon population in the Kootenai River was listed as endangered by the U.S. Fish and Wildlife Service in 1994. The Kootenai River White Sturgeon Study and Conservation Aquaculture Project was initiated by the Kootenai Tribe of Idaho as a stopgap measure in 1989 to produce fish from wild Kootenai River adults until effective habitat restoration measures could be identified and implemented. Only the long life span of the sturgeon has forestalled extinction to date. Natural recruitment has been absent or limited for decades and the current population of large old fish is steadily dwindling. Continued failure of natural recruitment means that the next generation of Kootenai white sturgeon will come almost entirely from the hatchery.

(dollars in thousands)

FY 2006	FY 2007	FY 2008

-Nez Perce Tribal Hatchery. Additional rearing and acclimation facilities are requested as part of the existing Nez Perce Tribal Hatchery for reintroduction of up to 700,000 Coho smolts into the Clearwater River in Idaho. Requires development and review of Master Plan prior to implementation. The Nez Perce Tribe (NPT) is motivated to implement the Clearwater Coho Restoration Project (CCRP) for the following reasons: 1) historically, coho salmon were one of the species making up a complex multi-species anadromous ecosystem within the Clearwater; 2) the 1855 Treaty with the United States reserved harvest rights at all usual and accustomed places; 3) coho salmon are a cultural resource to the NPT; and 4) the extirpation of coho salmon from the Snake River Basin remains unmitigated. The NPT goal is to restore coho salmon to the Clearwater subbasin measured by 14,000 adults at Lower Granite Dam annually. The 2007-2009 proposal is for completing the Step planning process and construction based on the 2004 Master Plan. Plans are to develop an integrated management plan to optimize the use of hatchery fish to meet recovery and harvest objectives.

-Redfish Lake Sockeye Captive Brood expansion: Project would expand the sockeye captive broodstock program by constructing new facilities at Eagle Hatchery in Idaho and Oxbow Hatchery in Oregon to annually produce up to 150,000 smolts. Project requires development and review of a Master Plan prior to implementation. This production number may increase depending upon the outcome of the BiOp Remand Collaborative Process. Precipitous declines of Snake River sockeye salmon led to their Federal listing as endangered in 1991 (56 FR 58619). In that same year, the Idaho Department of Fish and Game (IDFG) initiated a Captive Broodstock Program to maintain Snake River sockeye salmon and prevent species extinction. The ultimate program goal is to reestablish sockeye salmon runs to Stanley Basin waters and to provide for sport and treaty harvest opportunities. The program's near-term goal is to prevent species extinction, slow the loss of critical population genetic diversity and heterozygosity and increase the number of individuals in the population.

-Chief Joseph Dam Hatchery. BPA is proposing to fund the Chief Joseph Dam Hatchery Program, a comprehensive management program for supplementing Chinook salmon below Chief Joseph Dam, in Washington in the Okanogan subbasin and the Columbia River between the confluence of the Okanogan River and Chief Joseph Dam. Project includes a new hatchery facility (at the base of the Chief Joseph Dam) and acclimation ponds (throughout the Okanogan River subbasin), broodstock collection, egg incubation, rearing, release, and selective broodstock collection method development. The objective is to improve production of spring/summer and fall Chinook salmon in the Okanogan River Subbasin below Chief Joseph Dam. Planned production levels are 2 million summer/fall chinook and 0.9 million spring chinook smolts. Exploration of potential cost sharing for O&M is underway with several public utility districts having some level of mitigation responsibility for their hydro projects within this geographic area.

(dollars in thousands)		
FY 2006	FY 2007	FY 2008

-Hood River Production Facility. This project includes expansion of existing Parkdale fish facility to accommodate spring chinook rearing, construction of new Hood River adult salmonid trapping facilities, and development of alternative adult trapping sites. Powerdale Dam, which is owned and operated by PacifiCorp, is scheduled for decommissioning during the summer of 2010. The dam forms an integral part of the Powerdale Dam Fish Trap (PDFT), as fish are shunted into the fish trap as they ascend the fish ladder at the facility. Removal of the dam will also remove the fish trapping facility. The PDFT currently provides the foundation for many of the activities associated with implementation of the HRPP. These include: monitoring escapement, collecting life history characteristics, and broodstock acquisition. In order to continue implementing the Hood River Production Program (HRPP), alternative trapping sites will need to be developed. The HRPP has four primary goals: 1) Re-establish naturally sustaining runs of spring chinook in the Hood River; 2) Re-build naturally sustaining runs of summer and winter steelhead in the Hood River; 3) Maintain genetic characteristics of Hood River fish populations; and 4) Provide fish for sustainable harvest by both sport and tribal fishers.

-Mid Columbia Coho restoration. Indigenous natural coho salmon no longer occupy the mid-Columbia river basins. Columbia coho salmon populations were decimated in the early 1900s. For several reasons, including the construction and operation of mainstem Columbia River hydropower projects, habitat degradation, release locations, harvest management, and hatchery practices and genetic guidelines, self-sustaining coho populations were not re-established in mid-Columbia basins. Currently, the lack of locally adapted stock and in-basin habitat degradation may be the biggest challenges to coho reintroduction in mid-Columbia tributaries. This program's vision is to re-establish naturally reproducing coho salmon populations in the Wenatchee and Methow subbasins at biologically sustainable levels which provide significant harvest in most years.

Cultural, socio-economic, and ecological benefits are expected from the return of this species to areas where it once occurred in abundance. The phased approach incorporates development of a mid-Columbia hatchery broodstock, local adaptation to tributaries in the Wenatchee and Methow basins, and habitat restoration that will benefit coho as well as ESA-listed spring chinook, steelhead, and bull trout.

-Yakama Coho restoration. Before the ocean and lower Columbia exploitation of salmon and steelhead in the late l9th century and early 20th century, and before the Yakima River valley was developed, the Yakima Subbasin supported large runs of spring, summer and fall Chinook, summer steelhead, coho and sockeye. Historical returns of coho to the Yakima River Basin have been estimated in the range of 44,000 to more than 100,000 fish annually.

Cumulative effects from the disruption of the Yakima Subbasin ecosystem functions and processes, out of subbasin impacts, and harvest of salmon have resulted in a significant decline of fish and wildlife abundance from historic levels. Over the last ten years, Yakima River mouth returns of coho have ranged from about 800 to 6,200 salmon. The significant decrease in abundance of these fish is mirrored on the terrestrial landscape. The goal of this restoration project is to restore extirpated coho salmon to the Yakima River basin at biologically sustainable levels.

-Walla Walla River Juvenile and Adult Passage Improvements: This project would provide safe passage for migrating juvenile and adult salmonids in the Walla Walla Basin by constructing and maintaining passage facilities at irrigation diversion dams and canals.
-Walla Walla Hatchery planning and design. Project requires development and review of a Master Plan prior to implementation.

The FCRPS BiOp Remand Collaboration Process is currently assessing potential hatchery reform actions for all Federally funded hatcheries including those funded by BPA as part of the Council Integrated Fish and Wildlife Program and those programs funded directly by BPA through the Corps, USFWS and Bureau. Specific actions designed to benefit ESA-listed stocks to be funded have not yet been identified and depend upon the outcome of this regional collaborative process, anticipated to conclude in Spring/Summer 2007. Any new efforts will be identified at that time in the Action Agencies Updated Proposed Action and in updates to yearly implementation plans.

Potential Wildlife Habitat Acquisitions (Including Conservation Easements):
- Grand Coulee and Chief Joseph Wildlife Habitat Acquisition
- Couer d'Alene Fish and Wildlife Habitat Acquisition
- Albeni Falls Wildlife Mitigation.
- Blue Creek Winter Range Wildlife Habitat Acquisition
- Yakima Valley Fish and Wildlife Habitat Acquisition
- Grande Ronde Wildlife Habitat Acquisition
- Salmon River Fish Habitat Acquisition
- Fish and Wildlife Land Acquisition - Selah Gap to Union Gap
- Palisades and Minidoka Wildlife Habitat Acquisition
- Black Canyon, Boise Diversion, Anderson Ranch Wildlife Habitat Acquisition
- Willamette Fish and Wildlife Habitat Acquisition
- Libby and Hungry Horse Reservoirs Resident Fish Acquisitions

	FY 2006	FY 2007	FY 2008
Conservation and Energy Efficiency	**20,058**	**32,000**	**32,000**

The conservation acquisition program offers several ways for customers to participate in regional conservation. Program components include: (1) utility standard offer and custom programs, which result in customer proposals to conserve energy through residential weatherization, commercial lighting and HVAC (Heating, Ventilation, and Air Conditioning), industrial processes and lighting, and irrigated agriculture; (2) third party delivery programs, such as residential compact fluorescent lighting, "Vending Mi$er" (a program to reduce energy use in regional refrigerated vending machines) and the Water and Waste Water Treatment Facilities program; (3) Federal programs to help Federal installations in the region reduce energy use, which includes the Federal Hatcheries program and work at various dams to help the Corps and Reclamation in their efforts to reduce energy use; and (4) other initiatives still in the design stage.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Total Power Services – Capital	**176,033**	**201,000**	**213,000**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Associated Project Costs	
▪ Slight increase is a reshaping of funding requirements based on the need to maintain a minimum level of generation each year	+12,000
Fish and Wildlife	
▪ Program costs average $36 million annually for FYs 2007 through the rate period	0
Conservation and Energy Efficiency	
▪ Funding is consistent with the Council's most recent Power Plan, finalized in 2005.	0
Total Funding Change, Power Services - Capital	**+12,000**

Transmission Services – Capital

Funding Schedule by Activity

Transmission Services - Capital	FY 2006	FY 2007	FY 2008
	(accrued expenditures) (dollars in thousands)		
Main Grid	10,925	69,581	93,216
Area & Customer Services	1,173	25,227	33,380
Upgrades & Additions	55,404	43,009	62,541
System Replacements	70,972	89,004	88,922
Projects Funded in Advance	47,917	138,883	77,494
Total, Transmission Services - Capital	186,391	365,704	355,553

Outyear Funding Schedule

	(accrued expenditures) (dollars in thousands)			
	FY 2009	FY 2010	FY 2011	FY 2012
Total, Transmission Services - Capital	329,640	350,539	351,955	363,593

Description

TS is responsible for about 75 percent of the Pacific Northwest's high-voltage transmission. TS provides for all additions, upgrades, and replacements to the Federal BPA transmission system, resulting in reliable service to northwest industrial users and utility customers. The Federal BPA transmission system also facilitates the sale and exchange of power to and from the region.

The eastern blackout on August 14, 2003, alerted the Nation to the lack of investment in utility transmission infrastructure. BPA has been working on infrastructure investments and operational practices to improve the transmission grid since the West Coast disturbance on August 10, 1996. TS has made, and continues to make significant infrastructure improvements and additions to the system to assure reliable transmission in the Northwest. These improvements and additions will help the Federal transmission system continue to comply with national reliability standards, replace aging equipment, allow for interconnection of needed new generation, and remove constraints that limit economic trade or the ability to maintain the system. Prior to beginning the infrastructure improvements, TS had built no major transmission projects since 1987. Only incremental additions had been added to the system over the years.

The Northwest transmission system continues to show signs of stress, as two close calls in 2003 demonstrated. On June 4, 2003, voltage instability in the Spokane area was prevented by quick operator action on the Federal system. Two weeks later, the non-Federal transmission path between Montana and Idaho was overloaded for two days, and operator adjustments prevented load loss. In 2004, it was noted that a small load change at BPA's interconnection with Idaho Power near LaGrande, Oregon, was causing an unusually large voltage change. These examples demonstrate how the transmission system is being ‘pushed’ to its limits of capacity to carry power. The completions of the Grand Coulee-Bell, Kangley-Echo Lake, and Schultz-Wautoma lines projects have provided dispatchers with a greater Operator’s Transfer Capability, and have reduced the likelihood of outages or reduction of transmission capacity for outage situations.

Bonneville’s completed infrastructure investments that further strengthen the network consist of the following projects:

Puget Sound Area Additions, North of Hanford/ North of John Day, Cross Cascades North, Celilo Modernization, Eastern Washington Reinforcement, Portland Area Additions.

These projects relieve congestion and contribute toward restoring an adequate reliability margin back into the grid. These additional margins will be used to respond to a competitive market, meet regional load during outages, move power to meet changing loads, perform maintenance without harming the market, and allow Columbia Grid (formerly referred to as Grid West) to start with the regional grid less congested.

In 2005, with the Congressional approval of wind tax credits, a number of potential wind generation companies have made requests for connection to the BPA transmission grid. In FY 2006 BPA energized two new substations to integrate new wind power projects for a total of 400 MWs of wind energy installed. Another 1200 MW is expected to be connected in FY 2007, and another 1200 MWs is expected by FY 2009. The wind generation being proposed is in addition to the 1,600 MW of gas and geothermal generation already being proposed. These new generation sources are adding additional stress in getting the power from generation to load in the Northwest.

Bonneville assumes that some generators will seek to interconnect their power projects into the Federal transmission system. Depending on which generators build on sites in the Northwest, and depending on the project locations, between 1000 and 1,600 MW can be interconnected and integrated with the completion of the above additions and improvements. Integration directly into the Federal transmission system will be consistent with BPA’s open access transmission tariff.

As a means to sustain BPA’s limited Treasury financing, third-party funding partnerships are currently being explored as a financing option for some investments.

System Replacements replace high-risk, obsolete, and maintenance-intensive facilities and equipment and reduce the chance of equipment failure by: 1) replacing high voltage transformers and power circuit breakers which are at or near the end of their useful life; 2) replacing risky, outdated and obsolete Control Center and control and communications equipment and systems; and now includes replacements provided for in the Commercial Spectrum Enhancement Act (CSE Act) (PFIA work); and 3) replacing all other existing high-risk equipment and facilities affecting the safety and reliability of the transmission system.

Bonneville will continue to fund fiber optic communications facilities needed to meet Bonneville’s projected operational needs. To the extent that these investments create temporary periods of excess fiber optic capacity, such dark fiber capacity can be made available to telecommunications providers and to non-profits to meet public benefit Internet access needs for rural areas and other needs in Bonneville’s service area. Bonneville’s investments in fiber optics, including the role of the private sector in building fiber optic networks, is consistent with the "Fiber Optic Cable Plan" submitted to Congress on May 24, 2000, accompanying the FY 2000 Energy and Water Development Appropriations Act. In accordance with this plan, when possible, Bonneville will establish partnerships with fiber optic facility and service providers to meet its needs.

In December 2004, the Congress passed and the President signed the Commercial Spectrum Enhancement Act (CSEA, Title II of P.L. 108-494), creating the Spectrum Relocation Fund (SRF) to streamline the relocation of Federal systems from certain spectrum bands to accommodate commercial use by facilitating reimbursement to affected agencies of relocation costs. The Federal Communications Commission has auctioned licenses for reallocated Federal spectrum, which will facilitate the provision of Advanced Wireless Services to consumers. Funds are made available to agencies in FY 2007 for relocation of communications systems operating on the affected spectrum. These funds are mandatory and will remain available until expended, and agencies will return to the SRF any amounts received in excess of actual relocation costs. The estimated BPA cost of this relocation is $48.7 million.

As part of the Homeland Security Presidential Directives, Bonneville has completed a physical security assessment of all critical facilities and is implementing security enhancements at these facilities. These security enhancements increase access control to BPA's facilities and provide video surveillance and monitoring capabilities.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Main Grid	**10,925**	**69,581**	**93,216**

Bonneville's strategic objectives for Main Grid projects are to provide voltage support; provide a reliable transmission system for open access, per FERC criteria; provide for relief of transmission system congestion; and assure compliance with the National Electrical Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and BPA reliability standards. During this budgeting period, projects are planned that will provide voltage support to major load areas that are primarily west of the Cascade Mountains, and provide for transmission access for new generation projects to the load center. Reinforcements along the I-5 corridor are also planned.

- FY 2006: (1) Completed construction of the Schultz-Wautoma 500kV line and Wautoma Substation (North of Hanford/North of John Day); (2) Cancelled the construction of a 230 KV transformer in the Longview area replaced with Allston 230/115KV Transformer ; (3) Completed the construction of Allston 230/115kv Bank #1; (4) Completed planning studies and began environmental work for the Olympic Peninsula Reinforcement project ; (5) Continued the preliminary design for the Libby-Troy 115kv transmission line upgrade; (6) Continued planning studies to identify and clarify needed infrastructure additions; (7) Continued planning studies and design to comply with the NERC/ WECC reliability Standards; (8) Continued planning and design studies to comply with the N-2 outage criteria; (9) Continued planning studies to identify other system reactive needs to mitigate unacceptable low or high voltage problems and other system additions; (10) Continued planning studies to relieve the transmission system capacity congestion and for the integration of new generation facilities.

	(dollars in thousands)	
FY 2006	FY 2007	FY 2008

- FY 2007: (1) Begin the planning, design, material ordering of I-5 Corridor reinforcements; (2)Begin the design, material ordering and construction of the Libby-Troy 115kv transmission line upgrade; (3) Complete the environmental work for the Olympia Peninsula Reinforcement project; (4) Begin the Preliminary Engineering and Environmental Impact Statement (EIS) for West of McNary Generation Integration Project; (5) Continue planning studies to identify and clarify needed infrastructure additions; (6) Continue planning studies to identify projects driven by NERC/ WECC reliability Standards; (7) Continue planning and design studies to comply with the N-2 outage criteria; (8) Continue planning studies to identify addition system reactive needs to mitigate unacceptable low or high voltage problems and other system additions; (9) Continue planning studies to relieve the transmission system capacity congestion and to integrate new generation facilities.

- FY 2008: (1) Continue design, material ordering and begin the construction of I-5 Corridor reinforcements; (2) Continue the design and construction of the Libby-Troy 115KV transmission line upgrade; (3) Continue design, material ordering and construction for the Olympic Peninsula Addition project (4) Continue the preliminary engineering and complete the EIS for the West of McNary Generation Integration Project; (5) Continue planning studies to identify and clarify needed infrastructure additions; (6) Continue planning studies and design to identify projects driven by NERC/ WECC reliability Standards; (7) Continue planning and design studies to comply with the N-2 outage criteria; (8) Continue planning studies to identify other system reactive needs to mitigate unacceptable low or high voltage problems and other system additions; (9) Continue planning studies to relieve the transmission system capacity congestion and for integrating potential new generation facilities.

	FY 2006	FY 2007	FY 2008
Area and Customer Services	**1,173**	**25,227**	**33,380**

Bonneville's strategic objective for Area and Customer Service projects is to assure that Bonneville meets the reliability standards and the contractual obligations we have to our customers for serving load.

- FY 2006: (1) Completed design for the Static VAR Compensator (SVC) at Rogue Substation to serve South Oregon Coast; (2) Begin design work on new Caribou Substation subject to 4 utility agreement being in place; (3) Begin re-conductoring the Chehalis-Centralia 69KV #1 & #2 lines which was changed to a double circuit rebuild of a portion of the Chehalis- Centralia 69kV #2 line; (4) Added two 115kV breakers at Red Mountain Substation – project cancelled after further study; (5) Added SVC for Condon wind generation – project cancelled after further study; (6) Continued preliminary engineering and design for miscellaneous facilities required to meet contractual obligations and maintain reliable service for BPA's service area.

- FY 2007: (1) Begin construction of the SVC at Rogue Substation to serve Southern Oregon Coast; (2) Cancelled the design for shunt capacitor addition at Fords Prairie area; (3) Continue design and material ordering and begin construction of the new Caribou Substation; (4) Begin design and construction to rebuild Chehalis-Ford's Prairie Section of the Chehalis-Centralia 69kV #2 line to double circuit (Part of the City of Centralia Reinforcement Project); (5) Continue preliminary engineering and design for miscellaneous facilities required to meet contractual obligations and maintain reliable service for BPA's service area.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

- FY2008: (1) Begin design for the addition of the SVC at Port Angeles Substation; (2) Complete construction on Caribou Substation; (3) Complete design and construction of the Shunt Capacitor addition at Madison Substation; (4) Complete the City of Centralia Reinforcement Project; (5) Continue preliminary engineering and design for miscellaneous facilities required to meet contractual obligations and maintain reliable service for BPA's service area.

Upgrades & Additions	**55,404**	**43,009**	**62,541**

Bonneville's strategic objectives for Upgrades and Additions are to replace older communications and controls with newer technology including fiber optics in order to maintain or enhance the capabilities of the transmission system; to implement special remedial action control schemes to accommodate new generation and mitigate immediate operational and market constrained paths; and, to support communications and remedial action schemes, among other proposals.

During this budget period, BPA will complete design, material acquisition, construction and activation of several fiber optics facilities to provide bandwidth capacity and high-speed data transfers to eventually replace microwave analog radios, which are technologically obsolete and nearing the end of their useful life. Temporarily, in some areas, excess fiber capacity is being offered for a term to telecommunications providers or to public entities such as public utilities, schools, libraries, and hospitals, providing them access to high-speed telecommunication services as a public benefit.

- FY 2006 (1) Completed the Thompson Falls to Taft sections of the 175 mile Noxon-Hatwai fiber optic project; (2) Completed of the 32 mile Pearl-Troutdale fiber optic project; (3) Delayed the 40 mile Pearl-Marion fiber optic project (pending the start of the Sempra generation project); (4) Continued developing project scope and agreement for the Snohomish-Bellingham fiber optic project; (5) Completed one mile fiber installation and fiber termination at Thompson Falls Radio Station; (6) Continue construction of secondary fiber related projects and digital radio system upgrades to improve the operational telecommunication system; (7) Continued replacement and upgrade of operational and marketing business tools at the Dittmer and Munro control centers; (8) Continued planning, design, material acquisition and construction of special remedial action control schemes required for interconnecting new generation projects and mitigating immediate constrained paths; (8) Continued planning, design, material acquisition and construction of various system additions and upgrades necessary to maintain a reliable system for BPA's service area.

- FY 2007: (1) Continue developing project scope and agreement for the Snohomish-Bellingham fiber optic project; (2); Complete design and construction for the 2 mile taps for Sifton and Kennewick Fiber optic projects; (3) Continue construction of secondary fiber related projects and digital radio system upgrades to improve the operational telecommunication system; (4) Continue replacement and upgrade of operational and marketing business tools at the Dittmer and Munro control centers; (5) Complete design and construction of seismic upgrade projects, (6) Continue planning, design, material acquisition and construction of special remedial action control schemes required for interconnecting new generation projects and mitigating immediate constrained paths; (7) Continue planning, design, material acquisition and construction of various system additions and upgrades necessary to maintain a

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

reliable system for BPA's service area.

- FY 2008 (1) Begin the design and material acquisition for Snohomish – Bellingham fiber project; (2) Begin design and material ordering for the Celilo Upgrades (Controls and Protection) project; (3) Complete design and construction of seismic upgrade projects; (4) Continue planning, design, material acquisition and construction of special remedial action control schemes required for interconnecting new generation projects and mitigating immediate constrained paths; (5) Continue planning, design, material acquisition and construction of various system additions and upgrades necessary to maintain a reliable system for BPA's service area.

System Replacements	**70,972**	**89,004**	**88,922**

Bonneville's strategic objectives for System Replacement are to replace high-risk, obsolete, and maintenance-intensive facilities and equipment and to reduce the chance of equipment failure by: 1) replacing high voltage transformers and power circuit breakers which are at or near the end of their useful life; 2) replacing risky, outdated and obsolete control and communications equipment and systems, and now includes mandated replacements due to legislation; 3) replacing all other existing high-risk equipment and facilities affecting the safety and reliability of the transmission system.

Non-Electric Replacements:

- FY 2006: (1) Completed other non-electric replacements as necessary; (2) Continued the design, material acquisition, and construction for the Access Road Program; (3) Completed 12 security enhancement projects at various substations.

- FY 2007: (1) Complete other non-electric replacements as necessary; (2) Continue the design, material acquisition, and construction for the Access Road Program; (3) Complete 12 security enhancement projects at various substations. (4) Complete order for replacement of three BPA helicopters for future delivery utilizing General Services Administration exchange sale authority; (5) Complete order for replacement of two fixed wing aircraft utilizing General Services Administration exchange sale authority and receive delivery of one.

- FY 2008 (1) Complete seismic upgrades to substations and buildings; (2) Complete other non-electric replacements as necessary; (3) Continue the design, material acquisition, and construction for the Access Road Program; (4) Complete 12 security enhancement projects at various substations; (5). Receive delivery of one fixed wing aircraft utilizing General Services Administration exchange sale authority.

Electric Replacements:

- FY 2006: (1) Completed replacement of system protection and control equipment and other substation and line facilities as needed to maintain reliability using Reliability Centered Maintenance (RCM) criteria. Such replacements include relays, annunciators, oscillographs, metering and replacing and migrating analog to digital technology and to Supervisory Control and Data Acquisition (SCADA) equipment; (2) Completed replacement of under-rated and high maintenance substation equipment; (3) Completed replacement of spacer dampers on various 500kV lines; (4) Completed replacement of critical, operational tools and marketing business systems at the Dittmer and Munro Control Centers; (5) Continued replacing deteriorating wood pole transmission line structures, spacer dampers and insulators with Non-Ceramic Insulators (NCI).

(dollars in thousands)

- FY 2007: (1) Continue replacement of system protection and control equipment and other substation and line facilities as needed to maintain reliability using RCM criteria. Such replacements include relays, annunciators, oscillographs, metering and replacing and migrating analog to digital technology and SCADA equipment; (2) Continue replacement of under-rated and high maintenance substation equipment; (3) Continue replacing spacer dampers on various 500kV lines; (4) Continue replacing critical, operational tools and marketing business systems at the Dittmer and Munro Control Centers; (5) Continue replacing deteriorating wood pole transmission line structures and insulators with NCI.

- FY 2008: (1) Continue replacement of system protection and control equipment and other substation and line facilities as needed to maintain reliability using RCM criteria. Such replacements include relays, annunciators, oscillographs, metering and various types of communication related equipment replacing and migrating analog to digital technology and SCADA equipment; (2) Continue replacement of under-rated and high maintenance substation equipment; (3) Continue replacing spacer dampers on various 500kV lines; (4) Continue replacing critical, operational tools and marketing business systems at the Dittmer and Munro Control Centers; (5) Continue replacing deteriorating wood pole transmission line structures, spacer dampers and insulators with NCI.

Projects Funded in Advance	**47,917**	**138,883**	**77,494**

This category includes those facilities and/or equipment where BPA retains control or ownership but which are funded by a third party or with revenues, either in total or in part.

- FY 2006: (1) Completed the integration of various new wind generation projects into BPA transmission grid per Transmission Service Request via the Open Access Tariff; (2) Completed construction of the Schultz-Wautoma 500 KV transmission line; (3) Begin planning and design studies to install an SVC at Captain Jack substation; (4) Completed studies to identify system impacts and needs regarding proposed new generation projects; (5) Completed environmental cleanup and other work necessary for the sale of BPA facilities; (6) Completed other projects as agreed to with customers.

- FY 2007: (1) Continue to integrate various new wind generation projects into BPA transmission grid per Transmission Service Request via the Open Access Tariff; (2) Begin the EIS and preliminary engineering for the SVC at Captain Jack Substation; (3) Complete planning studies to identify system impacts and needs regarding proposed new generation projects; (4) Complete environmental cleanup and other work necessary for the sale of BPA facilities; (5) Complete other projects as agreed to with customers. (6) Begin preliminary engineering for the radio replacements associated with the CSE Act.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

- FY 2008 (1) Continue to integrate various new wind generation projects into BPA transmission grid per Transmission Service Request via the Open Access Tariff; (2) Complete the design and construction of the SVC at Captain Jack;(3) Continue planning studies to identify system impacts and needs regarding proposed new generation projects; (4) Continue environmental cleanup and other work necessary for the sale of BPA facilities; (5) Complete other projects as agreed to with customers; (6) Begin the design and construction for various radio replacements at accessible sites.

Total, Transmission Services – Capital	**186,391**	**365,704**	**355,553**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Main Grid	
▪ Reflects fiscal year shifts in material and construction costs and to accommodate projects associated with updated power flow study results	+23,635
Area & Customer Services	
▪ Reflects greater emphasis on customer service projects	+8,153
Upgrades & Additions	
▪ Reflects increased emphasis on both systemwide communications upgrades and improvements and additions to other transmission facilities	+19,532
System Replacements	
▪ Minor decrease reflects continuing focus on system replacements	-82
Projects Funded in Advance	
▪ Reflects completion of large customer funded projects related to generation integration	-61,389
Total Funding Change, Transmission Services - Capital	-10,151

Capital IT & Equipment/Capitalized Bond Premium

Funding Schedule by Activity

(accrued expenditures)
(dollars in thousands)

Capital IT & Equipment/Capitalized Bond Premium	FY 2006	FY 2007	FY 2008
Capital Information Technologies (IT) & Equipment	17,671	32,785	47,421
Capitalized Bond Premium	0	0	0
Total, Capital IT & Equipment/Capitalized Bond Premium	17,671	32,785	47,421

Outyear Funding Schedule

(accrued expenditures)
(dollars in thousands)

	FY 2009	FY 2010	FY 2011	FY 2012
Total, Capital IT & Equipment/Capitalized Bond Premium	32,187	31,363	26,116	27,170

Description

Capital Information Technologies provides for the acquisition of general and some dedicated special purpose capital information technologies, and acquisition of special-use capital and IT equipment in support of Bonneville's strategic objectives.

As part of a major efficiency effort and in support of the President's Management Initiative on Expanded Electronic Government, BPA is moving its IT infrastructure to a more efficient architecture. This FY 2008 budget incorporates the results of this effort. IT is seeking to eliminate redundancies in tools and applications, establish an agency-wide IT architecture with standardized IT purchasing criteria, standardize software licensing processes and minimize agency liabilities through stronger contracts, improve IT project management, and formulate an agency IT portfolio cost management strategy. The IT estimates in this FY 2008 budget, under Capital Information Technologies and Equipment include all IT functions within the agency except TS grid operations. See the Capital Program – Transmission Services section of this budget for additional discussion of transmission-related IT requirements acquisitions.

Capital equipment provides for the acquisition of general and some dedicated special purchases of capital office furniture and equipment.

Bonneville incurs a bond premium whenever it repays a Treasury bond before the due date. When bonds are refinanced, the bond premiums incurred are capitalized. Historically, Bonneville generally has chosen to finance capitalized bond premiums with bonds issued to the Treasury, as was envisioned in the Transmission System Act of 1974. In this FY 2008 budget, no capitalized bond premiums are forecasted consistent with market expectations.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Capital Information Technology/Equipment	**17,671**	**32,785**	**47,421**

- Includes enhancements to Bonneville's information technology processes to provide cost effective efficiencies for secure, timely and accurate information. Continue enhancements to Bonneville's Enterprise systems that are designed to link key information systems throughout Bonneville and improve business processes. Current efforts include continued functional consolidation into areas not implemented during the initial development phase. Acquire capital office furniture and equipment, capital automatic data processing (ADP) - based administrative telecommunications equipment, ADP equipment (hardware), and support capital software development for certain Bonneville programs.

Capitalized Bond Premium.	**0**	**0**	**0**

- Continue to assess financial market and when cost-effective, refinance available bonds as prudent.

Total, Capital IT & Equipment/Capitalized Bond Premium	**17,671**	**32,785**	**47,421**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Capital Information Technology & Equipment	
■ Reflects emphasis on IT infrastructure architecture and Enterprise efficiency improvements.	+14,636
Capitalized Bond Premium	
■ No change	0
Total Funding Change, Capital Equipment/Capital Bond Premium	+14,636

Power Services - Operating Expense

Funding Schedule by Activity

(accrued expenditures)
(dollars in thousands)

Power Services - Operating Expenses	FY 2006	FY 2007	FY 2008
Production	1,228,391	1,295,810	1,094,208
Associated Projects Costs	246,527	268,741	277,356
Fish & Wildlife	137,862	143,000	143,000
Residential Exchange	156,167	336,699	336,861
NW Power & Conservation Council	8,512	9,085	9,266
Conservation and Energy Efficiency	63,194	66,014	65,104
Total, Power Services - Operating Expenses	1,840,653	2,119,349	1,925,795

Outyear Funding Schedule

(accrued expenditures)
(dollars in thousands)

	FY 2009	FY 2010	FY 2011	FY 2012
Total, Power Services - Operating Expense	2,170,217	1,962,051	2,027,912	1,916,545

Description

Production includes all Bonneville non-Federal debt service (including ENW debt), O&M of power system generation resources, including a large nuclear plant, business operations, short- and long-term power purchases, electric utility marketing of power, and oversight of hydro and nuclear projects. These activities identify the Administrator's load obligations, develop product plans and services to meet the needs of Bonneville customers and stakeholders, and acquire resources as needed.

ENW debt is one of Bonneville's largest expense components. As part of its continuing competitive efforts, Bonneville is working to further optimize debt service costs (often referred to as debt optimization elsewhere in this budget). Bonneville has reached agreement with ENW to pursue refinancing of certain ENW bonds. Bonneville pays the debt service on these bonds under the terms of earlier net billing agreements. A component of the refinancing strategy is to extend the final maturity on the Columbia Generating Station (formerly WNP-2) debt. In addition, for Projects 1 and 3, some debt currently maturing prior to FY 2012 is being extended into the FY 2013-2018 time period. Bonneville has committed to ENW to use the reductions in debt service resulting from this extension to amortize Federal debt earlier than currently scheduled, except in the case of an extreme financial emergency.

As a means of mitigating power market risk, Bonneville's Hedging Policy allows the use of financial instruments in the power, natural gas, aluminum, and interest rate markets to hedge the price of electricity and reduce Bonneville's exposure to market fluctuations and certain index sales contract provisions.

Associated Projects represents funding for operation and maintenance costs for the FCRPS, minor additions, improvements and replacements, and liabilities of the Corps and Reclamation hydroelectric projects in the Pacific Northwest, which serve many purposes. All agencies emphasize efficient power production from existing facilities and improvement of the performance and availability of power generating units. Bonneville pays additional financing costs of the FCRPS facilities through its Interest Expense and Capital Transfer budget programs. Bonneville provides funding for the operations and maintenance costs that are part of the Lower Snake River Compensation Plan (LSRCP) hatcheries. Bonneville is responsible for annual payments to the Confederated Tribes of the Colville Reservation for their claims concerning their contribution to the production of hydropower by the Grand Coulee Dam in accordance with the Settlement Agreement between the United States and the Tribes (April 1994).

Bonneville's Fish and Wildlife Program provides for the protection, enhancement, and mitigation of Columbia River Basin fish and wildlife due to losses attributed to the development and operation of Federal hydroelectric projects on the Columbia River and its tributaries from which Bonneville markets power. Bonneville satisfies a major portion of its fish and wildlife responsibilities pursuant to Section 4(h) of the Northwest Power Act by funding projects and activities designed to be consistent with the Council Fish and Wildlife Program.

Bonneville is also mandated to implement measures called for under the ESA. These measures are part of the most recent biological opinions issued in November 2004 by NOAA Fisheries and in 2006 by the USFWS to address the effects of the operation of the FCRPS on threatened and endangered salmon and steelhead and ESA-listed Kootenai River white sturgeon and bull trout. The biological opinions require the FCRPS Action Agencies to implement actions in the Columbia River Basin that address impacts of the Federal hydrosystem on ESA-listed fish to ensure that operation of the FCRPS does not jeopardize the continued existence of listed species or adversely modify their designated critical habitat. In February 2005, the FCRPS Action Agencies published an implementation plan for their proposed action addressed in the NOAA Fisheries 2006 Biological Opinion. The implementation plan, together with projects undertaken to address mitigation for non-listed species under the Northwest Power Act, and those to address requirements of the USFWS 2006 Biological Opinion form the basis for Bonneville's planned capital investment of $36 million for FYs 2007 and 2008.

The 2004 BiOp was also challenged in Federal District Court. In October 2005, the District Court invalidated the 2004 BiOp, although leaving it "in place" during the remand period. The Judge also ordered the sovereign parties to collaborate during the remand process, to try to find an acceptable approach for the 2004 BiOp that would have regional support. In December, the Department of Justice filed a notice to appeal the District Court's October 2005 remand order. However, the Federal parties continue to support the court ordered collaboration on the 2004 BiOp, even though an appeal has been filed.

There has also been litigation directed at the USFWS Biological Opinions for Libby dam. In 2003, the Corps and BPA reinitiated consultation for the operations at Libby dam to address impacts to recently designated critical habitat for the Kootenai River white sturgeon, and to evaluate information that had been developed on Kootenai River white sturgeon and bull trout since the 2000 USFWS BiOp. That consultation was completed in February 2006, but has now been challenged by environmental groups, the Kootenai Tribe, and the State of Montana in Federal district court of Montana.

Bonneville's fish and wildlife expenditures funds will focus on activities that benefit Columbia River Basin fish and wildlife resources including projects, consistent with priorities established in newly adopted Council Sub-basin Plans, designed to:

- increase survival of ESA-listed and non-listed fish at FCRPS dams and reservoirs;
- increase survival of ESA-listed and non-listed fish throughout their life cycle by protecting and enhancing important habitat areas;
- reform hatchery practices that affect ESA-listed populations and use hatcheries to contribute to conservation and recovery of ESA-listed and non-listed fish;
- provide for offsite mitigation projects for habitat, passage, and other improvements that address limiting factors for target species as defined in Sub-basin Plans;
- reduce harvest-related mortality on ESA-listed and non-listed fish and support sustainable fisheries; and;
- support a focused and well-coordinated research, monitoring, and evaluation program.

To the extent possible, Bonneville is integrating the actions implemented in response to the FCRPS Biological Opinions with projects implemented under the Council's Fish and Wildlife Program. Recently completed Sub-basin Plans that include prioritized strategies for mitigation actions will help guide project selection that meets both BPA's ESA and Northwest Power Act responsibilities. Discussion of a minimum cost-sharing requirement for fish and wildlife projects funded by BPA in 2007 and beyond is continuing in currently ongoing discussions with the Council and the regional fish and wildlife manager, customers, and Tribes. BPA established a Cost Sharing MOU with the US Forest Service in FY 2007 that requires a programmatic 30 percent cost share for fish mitigation projects funded by BPA on US Forest Service lands.

As part of these discussions for the Integrated Fish and Wildlife Program, BPA has recommended a reorientation and transition of the program over FYs 2007 – 2009 that places greater emphasis on projects that are performance based and deliver more results on-the-ground. On-the ground results include habitat protection, enhancement, tributary passage, screening and hatchery efforts. Recommended guidelines are 70 percent of overall program funding for on-the-ground projects; 25 percent to research, monitoring and evaluation (RM&E); and 5 percent for coordination, data management and administration. These estimates as well as those for other BPA fish program costs may change, however, depending upon evolving circumstances including the long-term effect of the Federal district court decision on the 2004 BiOp and the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion.

The FY 1997 Energy and Water Development Appropriations Act added section 4(h)(10)(D) to the Northwest Power Act, directing the Council to appoint an Independent Science Review Panel (ISRP) "to review a sufficient number of projects" proposed to be funded through Bonneville's fish and wildlife budget "to adequately ensure that the list of prioritized projects recommended is consistent with the Council's program," The Northwest Power Act further states that " . . . in making its recommendations to Bonneville, the Council shall consider the impact of ocean conditions on fish and wildlife populations; and shall determine whether the projects employ cost effective measures to achieve program objectives." The Conference Report on the FY 1999 Energy and Water Development Appropriations Act included a new assignment for the ISRP and the Council. The ISRP was to review the fish and wildlife projects, programs, or measures included in Federal agency budgets that are reimbursed, and/or directly funded, by Bonneville and to make funding recommendations to Congress. The ISRP was directed to determine whether the proposals are consistent with the scientific criteria in the Northwest Power Act as amended in

1996, and provide a report to the Council by April 1 of each year. The Council, in turn, must report to the Congress annually by May 15. Consequently, projects funded by Bonneville under the Program must be reviewed and prioritized as part of the Council recommendation process.

Consistent with the principles of the Federal Caucus' All-H Strategy, Bonneville is implementing much of the off-site mitigation actions required by the FCRPS Biological Opinions through the Council's Fish and Wildlife Program. Under the Northwest Power Act, the Fish and Wildlife Program is tasked with protecting and mitigating the Columbia River Basin fish and wildlife affected by the development and operation of all hydroelectric projects in the basin.

The Northwest Power Act created the REP to extend the benefits of low-cost Federal power to the residential and small farm customers of Pacific Northwest electric utilities that meet certain conditions. The 1996 Comprehensive Regional Review recommended that Bonneville engage in settlement discussions regarding the Residential Exchange. Bonneville then developed a Subscription Strategy based on the recommendations of the Comprehensive Review. That strategy proposed a comprehensive settlement of the REP for IOUs in the Pacific Northwest, which has resulted in new contracts with regional IOUs that provide power and monetary benefits to their residential and small farm customers.

Under the REP Settlement Agreements for FY 2007 through FY 2011, monetary benefits are determined by the difference between BPA's Forward Flat-Block Price Forecast (FBPF) and the RL rate (or lowest PF rate in appropriate circumstances) multiplied by the amount of the investor-owned utility's benefits as stated in annual aMW.

The proposed contracts replace the use of a rate case power price forecast with a mark-to-market methodology that is functionally similar to the rate case forecast used during FY 2002-2006, yet provides a desired transparency for determining the forecast. The new methodology uses an independent survey of market prices. The survey will use the prices for a flat block of firm power delivered at the Mid-C trading hub for each contract year.

Bonneville's preference utilities, or public agency utilities, have been eligible to execute new REP contracts since October 2001, except for the nine utilities that previously executed settlement agreements for terms ending July 1, 2011. One public agency customer has requested a contract for participation in the REP, which resulted in a settlement. Other public agency customers may also request a contract for participation.

The Northwest Power Act directs that expenses of the Council, subject to certain limits based on forecasted Bonneville power sales, shall be included in Bonneville's annual budget to Congress. Funding for the Council is provided by Bonneville and is recovered through Bonneville power rates. Its major activities include the periodic preparation of a Northwest Conservation and Electric Power Plan (a 20-year electric energy demand and resources forecast and energy conservation program) and a Columbia River Basin Fish and Wildlife Program of loss mitigation and resource enhancement actions.

In accordance with the Council, BPA will acquire conservation resources and act as a catalyst for energy efficiency and direct application renewables. These resources will: 1) meet conservation targets; 2) achieve a least cost resource mix; 3) dampen the cost impacts of power purchases; 4) avoid the costs of ramping programs and infrastructure up and down; 5) extend the value of the

FCRPS to customers; and 6) build the region's resource portfolio with conservation and direct application renewables**.** Bonneville also is exploring how best to integrate demand-side management, distributed generation, and other leading edge technologies (i.e., Energy Web program and non wires solutions) into its transmission planning process.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Production	**1,228,391**	**1,295,810**	**1,094,208**

- Power Purchases: Includes purchased power to cover load commitments as well as balancing the hydro system. These purchases can be made in the form of long-term purchases to meet load commitments based on long-term planning requirements or they can be made within the year to meet load commitments due to the monthly shape of the loads and the monthly shape of the hydro electric generation. Also, purchases can be made within the month and within the day to fill shortages due to fluctuations in the hydro system and load commitments.

- Power Scheduling/Marketing: Schedule and market (buy/sell) electric energy with Bonneville customers and the Pacific Northwest's interconnected utilities. Scheduling includes PS's implementation of physical and memo power schedules and associated transmission schedules, implementation of Electronic Tagging (ETag) in accordance with NERC and in accordance with FERC, implementation of electronic scheduling and the Columbia Grid as it evolves.

- Trojan: Decommissioning activities are complete and the Trojan operating license has been terminated by the NRC. BPA's 30 percent share of the demolition of buildings and site restoration activities will continue in the FY 2006 – FY 2008 period.

- Columbia Generating Station (formerly WNP-2): Continue to acquire full capability of Columbia Generating Station (Columbia). Columbia is on a 24-month fuel and outage cycle. A maintenance and refueling outage is planned for FY 2007 and FY 2009.

- WNP-1/WNP-3: Continue to fulfill contractual obligations for WNP-1 and WNP-3.

- Long-Term Power Purchases and Wheeling: Continue to acquire 100 percent of the 18.6 MW output of the Foote Creek 2 and 4 wind projects and a 15-kW share of the output from the Solar Ashland Project. Continue to acquire 90 MWs of Stateline wind project. Continue to acquire 100 percent of the output of the Condon and Klondike wind projects.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

Generation and Oversight:

FY 2006: Continue to provide oversight of all contracts signed to date. Provide oversight of large thermal generating plants from which Bonneville purchases capability to ensure that all Bonneville approval rights are protected; coordinate, communicate, and administer agreements, issues, and programs between Bonneville and the project owners. Continue to provide wind resource integration services for customer wind generation.

FY 2007: Continue to provide oversight of all contracts signed to date. Work with regional stakeholders to determine which (if any) products, actions or investments BPA should pursue to best facilitate renewable development in the Pacific Northwest. Continue to provide wind resource integration services for customer wind generation.

FY 2008: Continue to provide oversight of all contracts signed to date. Continue to provide wind resource integration services for customer wind generation.

Associated Project Costs	**246,527**	**268,741**	**277,356**

- Support FCRPS project costs and work to strengthen relationships to improve project support and better understand project costs. This helps to maintain FCRPS system integrity and to attain BPA's strategic business objectives.

- Bureau of Reclamation:
  FY 2006: Continued direct funding Reclamation O&M power activities.
  FY 2007: Continue direct funding Reclamation O&M power activities.
  FY 2008: Continue direct funding Reclamation O&M power activities.

- Corps of Engineers:
  FY 2006: Continued direct funding Corps O&M power activities.
  FY 2007: Continue direct funding Corps O&M power activities.
  FY 2008: Continue direct funding Corps O&M power activities.

Fish and Wildlife	**137,862**	**143,000**	**143,000**

- In a manner consistent with the assumptions used for the PFR process:

  New subbasin plans have been completed that describe management objectives and priorities for fish and wildlife within the Columbia River Basin. This effort has provided the basis for a new solicitation of proposals for potential funding by BPA and other responsible parties beginning in FY 2007. However, this solicitation and funding decisions for specific projects will not occur until the fall of 2007.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008

- Anadromous Fish: Continue implementing both ongoing and new projects that support ESA-listed species and other measures called for under the 2004 BiOp and amended FCRPS Action Agency proposal, consistent with the successful outcome of the remand collaborative process in shaping a regionally agreed upon new Biological Opinion, prioritized projects that address the factors that limit mitigation success as identified in the new subbasin plans and that fulfill BPA's responsibility for mitigation of the FCRPS. Implement and develop activities that protect and enhance tributary and estuary habitat, improve mainstream habitat on an experimental basis, reduce potentially harmful hatchery practices on ESA-listed populations, and contribute to sustainable fisheries. These activities have been selected in response to the Northwest Power Act section 2(6) to "protect, mitigate and enhance fish and wildlife including related spawning grounds and habitat on the Columbia River and its tributaries."

- Resident Fish: Implement activities to determine the impacts of the FCRPS on bull trout and mitigate for those impacts, and promote the reproduction and recruitment of Kootenai River white sturgeon. These activities have been selected in response to the USFWS 2000 Biological Opinion and the Northwest Power Act requirement to "protect, mitigate and enhance fish and wildlife including related spawning grounds and habitat on the Columbia River and its tributaries."

- Continue mitigation in resident fish for anadromous losses (substitution), mitigation for reservoir operation impacts to resident fish, and continue to refine, quantify, and delineate the difference between the two. Those resident fish acquisition projects that meet BPA's capitalization policy will be funded under the capital portion of Bonneville's fish and wildlife budget.

- Wildlife: Use existing Bonneville policies to continue the current program including funding for wildlife actions resulting from Council Fish and Wildlife Program amendments for wildlife mitigation. These activities have been selected in response to the Northwest Power Act requirement to "protect, mitigate and enhance fish and wildlife including related spawning grounds and habitat on the Columbia River and its tributaries." Those wildlife acquisition projects that meet BPA's capitalization policy will be funded under the capital portion of Bonneville's fish and wildlife budget.

Residential Exchange	**156,167**	**336,699**	**336,861**

- Includes negotiated contract settlement agreement costs related to monetary benefits.

Northwest Power and Conservation Council	**8,512**	**9,085**	**9,266**

- Continue support of the Council activities, as directed under the Northwest Power Act, including regional power plan development and maintenance, and fish and wildlife program activities.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Conservation and Energy Efficiency	**63,194**	**66,014**	**65,104**

- Continue close-out of the legacy conservation resource acquisition contracts, which support Bonneville's contractual obligation to serve customer load growth.

- Provide credible, unbiased information or technical or financial support to conservation purposes. As an agency of the DOE, and with independent responsibilities based on its authorizing legislation, Bonneville has a statutory responsibility to provide support to certain conservation objectives that are governmental in nature, such as assisting in the development of emerging technologies and providing unbiased information to consumers. Bonneville is participating with other regional entities to support market transformation and development activities that meet the needs of Bonneville customers and create business opportunities for the private sector in the Pacific Northwest.

Total, Power Services – Operating Expense	**1,840,653**	**2,119,349**	**1,925,795**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Production	
■ Decrease primarily reflects a decrease in Energy Northwest Project debt service, change from a refueling year for CGS in 2007 to a non-refueling year in 2008, and decreasing power purchases over the FY 2007-2009 rate period	-201,602
Associated Project Costs	
■ Increase due to security, biological opinion requirements, and improvements, replacements, and minor additions at the projects	+8,615
Fish and Wildlife	
■ Consistent funding levels reflect funding associated with Biological Opinion and Northwest Power Act activities	0
Residential Exchange Program	
■ Increase due to REP settlement agreement provisions	+162
Northwest Power and Conservation Council	
■ Small increase reflects continuing Council program activities	+181

Conservation and Energy Efficiency

▪ Small decrease reflects normal program adjustments	-910
Total Funding Change, Power Services - Operating Expense	-193,554

Transmission Services - Operating Expense

Funding Schedule by Activity

Transmission Services - Operating Expense	(accrued expenditures) (dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Engineering	32,653	40,487	56,299
Operations	109,577	110,314	97,708
Maintenance	144,969	140,533	144,331
Total, Transmission Services - Operating Expense	287,199	291,334	298,338

Outyear Funding Schedule

	(accrued expenditures) (dollars in thousands)			
	FY 2009	FY 2010	FY 2011	FY 2012
Total, Transmission Services - Operating Expense	308,885	310,928	314,533	318,308

Description

This activity provides for the transmission system services of engineering, operations, and maintenance for Bonneville's electric transmission system, consisting of over 15,000 circuit miles (24,135 circuit kilometers) of lines, 238 substations, and the associated power system control and communication facilities, with an invested cost of more than $5.6 billion. Primary strategies of this program are: 1) maintain the safety and reliability of the transmission system; 2) increase the focus on customers; 3) optimize the transmission system; and 4) provide open and nondiscriminatory transmission access; and 5) improve Bonneville's cost effectiveness.

Detailed Justification

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Engineering	**32,653**	**40,487**	**56,299**

Continue efforts to identify best methods for improving system reliability and maintenance practices, and continue cost reduction efforts by identifying opportunities for low-cost reinforcement and voltage support of the existing transmission system.

	(dollars in thousands)	
FY 2006	FY 2007	FY 2008

- R&D: Conduct in-house transmission system research and development, including (1) studies on reliability, High Voltage Direct Current (HVDC) and High Voltage Alternating Current (HVAC) outage reduction, (2) methods to update existing facilities and reduce maintenance costs including reliability-centered monitoring and recording methods for analysis.

- Technical Support: Provide technical support activities, such as transmission system planning and studies to optimize portions of the system. Provide support for non-wires solutions studies and pilot projects.

- Capital-to-Expense Adjustments: Conduct annual analysis of Bonneville's outstanding capital work orders to assess whether they should be expensed.

- Reimbursable Transactions: Enter into written agreements with Federal and non-Federal entities that have work or services to be performed by Bonneville staff at the expense of the benefiting utilities. The projects must be beneficial, under agreed upon criteria, to Bonneville operations and to the Federal or non-Federal entity involved. Additionally, these activities contribute to more efficient or reliable construction of the Federal transmission system or otherwise enhance electric service to the region.

- Leased and Other Costs: Includes leases and other costs of transmission, delivery and voltage support facilities when such arrangements are operationally feasible and cost effective to deliver power.

	FY 2006	FY 2007	FY 2008
Operations	**109,577**	**110,314**	**97,708**

- FY 2006: Continued to operate within parameters of regional transmission authorities. Prepared for increased complexity of outage scheduling, transmission scheduling, and dispatching, as well as impact of an expected high attrition rate of skilled operation dispatching workforce by recruiting and training apprentices and skilled replacements. Continued development and implementation of business systems and tools. Participated in planning and preparation for establishment of a regional transmission organization (RTO).

- FY 2007: Continue to operate within parameters of regional transmission authorities. Continue preparation for increased complexity of outage scheduling, transmission scheduling, and dispatching, as well as impact of an expected high attrition rate of skilled operation dispatching workforce by recruiting and training apprentices and skilled replacements. Continue development and implementation of business systems and tools. Participate in continued planning and preparation of Columbia Grid.

- FY 2008: Continue to operate within parameters of regional transmission authorities. Continue preparation for increased complexity of outage scheduling, transmission scheduling, and dispatching, as well as impact of an expected high attrition rate of skilled operation dispatching workforce by recruiting and training students, apprentices, and skilled replacements. Continue development and implementation of business systems and tools. Participate in planning and preparation for establishment of Columbia Grid.

- Substation Operations: Perform operations functions necessary to provide electric service to customers and to protect the Federal investment in electric equipment. Includes equipment adjustments, switching lines and equipment during emergencies or maintenance, isolating damaged equipment, restoring service to customers, and inspecting equipment, reading meters, et cetera.

- Power System Control and Dispatching: Perform central dispatching, control, and monitoring of the electric operation of the Federal transmission system. Also includes load, frequency, and voltage control of Federal generating plants, and operation of the system control and data computers at Dittmer and Munro Control Centers.

- Marketing and Sales: Provide management and direction of transmission rates, and provide business strategy in marketing of transmission and ancillary products and services of Transmission Services. Involve customers and constituents in the process of product and rate development. Maintain accurate and complete historical records of current and past transmission agreements. Provide guidance for current and future transmission contract negotiations. Provide financial analysis of market strategies. Monitor and report on the financial health of transmission services. Support cost management by effective reporting and analysis of current expenditures. Ensure official budget submittals reflect current management financial strategies and adequately fund transmission programs.

- Transmission Scheduling: Provide open access to the Federal transmission system consistent with the Open Access Transmission Tariff approved by FERC. Schedule and market transmission capacity to Bonneville customers, California ISO, and Pacific Northwest's interconnected utilities. Manage the reservations and scheduling of all transmission services associated with the Open Access Transmission Tariff.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
Maintenance	**144,969**	**140,533**	**144,331**

In all aspects of maintenance, Bonneville is continuing the implementation of RCM practices. This change is focused on improving system reliability and increasing availability in a deregulated market. Access road maintenance costs are expected to increase dramatically as Bonneville addresses the aging roads system and environmental constraints associated with construction, enhancement, and maintenance of access roads. The Bonneville transmission system encompasses approximately 50,000 miles of access roads (many of these roads are through rugged, inaccessible terrain). Cost for maintenance activities are budgeted at $1,000,000 annually.

- FY 2006: Continued to refine RCM practices at all of Bonneville's O&M regions. Continued to improve performance meeting System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) targets. Continued efforts to achieve the SAIFI and SAIDI targets of no control chart violations for circuit importance categories 1-2 (highest importance), and not more than one violation for category 4. Control charts are statistically based graphs that illustrate variability in performance. Continued to improve availability performance in a deregulated market by utilizing more efficient and cost-effective maintenance work practices and outage coordination. Used recruitment incentives to ensure succession of the current work force and remain competitive as an employer in the utility industry. Assured a safe work environment through safety awareness and improved work practices. Increased outage scheduling planning to increase customer satisfaction. Continued high levels of vegetation management and increased access road work to provide reliable access to facilities and ensure environmental compliance.

- FY 2007: Continue to refine RCM practices at all of Bonneville's O&M regions. Continue to improve performance to meet SAIFI and SAIDI targets as explained above. Continue to improve system availability performance through new maintenance procedures and work practices. Continue to prepare for the impact of an expected high attrition rate among Bonneville's aging workforce by recruiting apprentices and replacements for critical minimum crew size workload positions. Increase outage scheduling and coordination planning to increase customer satisfaction and system availability. Increase emphasis on non-electric facilities to compensate for years of deferral. Continue high emphasis of vegetation management, implementation of an aggressive access road management plan to maintain roads at a level that minimizes response time, increases reliability, and ensures environmental compliance.

- FY 2008: Continue to improve performance to meet SAIFI and SAIDI targets as explained above. Continue to improve system availability performance through new maintenance procedures and work practices. Continue to prepare for the impact of an expected high attrition rate among Bonneville's aging workforce by recruiting apprentices and replacements for critical minimum crew size workload positions. Increase outage-scheduling planning and coordination to increase customer satisfaction and system availability. Maintain vegetation management levels to ensure system reliability. Continue access road work to provide reliable access to facilities and ensure environmental compliance.

- Transmission Line Maintenance: Maintain and repair over 15,000 circuit miles (24,135 km) of high voltage transmission lines, of which over 6,436 km (4,000 circuit miles) are 500-kV transmission EHV (extra-high voltage), for which maintenance is two and one-half times more labor-intensive than maintenance of lower transmission voltages, although more efficient in transmission of power. This responsibility includes maintaining transmission rights-of-way to ensure system reliability, safety, and environmental compliance. Adopt work practices that improve system availability and reliability.

- Substation Maintenance: Maintain and repair the transmission system power equipment located in Bonneville's 238 substations. Work includes inspections, diagnostic testing, and predictive and condition based maintenance.

- System Protection Maintenance: Maintain relaying metering and remedial action scheme equipment used to control and protect the electrical transmission system and to meter energy transfers for the purpose of revenue billing. Additionally, field-engineering services provide technical advice and assure the correct operation of power system relaying and special control systems used to support interregional energy transmission capabilities.

- Power System Control Maintenance: Test, repair, and provide field engineering support of Bonneville's highly complex equipment, communications, and control systems, including seven major microwave systems, fiber optic systems, and other critical communications and control equipment that support the power system.

- Non-Electric Plant Maintenance: Maintain Bonneville's non-electric facilities. Includes site, building, and building utility maintenance; custodial services; station utility; and other maintenance service activities on Bonneville-owned or Bonneville-leased non-electric facilities.

	(dollars in thousands)		
	FY 2006	FY 2007	FY 2008
■ Maintenance Standards and Engineering: Establish, monitor, and update system maintenance standards, policies, and procedures, and review and update long-range plans for maintenance of the electric power transmission system.			
Total, Transmission Services - Operating Expense	**287,199**	**291,334**	**298,338**

Explanation of Funding Changes

	FY 2008 vs. FY 2007 ($000)
Engineering	
■ Increase reflects emphasis on system reliability improvements	+15,812
Operations	
■ Decrease reflects anticipated efficiency gains.	-12,606
Maintenance	
■ Increase primarily due to continuing maintenance program activities, including system protection, line maintenance, and performance improvements	+3,798
Total Funding Change, Transmission Services – Operating Expense.	+7,004

Interest, Pension and Post-retirement Benefits - Operating Expense and Capital Transfers

Funding Schedule by Activity

	(accrued expenditures) (dollars in thousands)		
Interest, Pension and Post-retirement Benefits	FY 2006	FY 2007	FY 2008
BPA Bond Interest (Net)	115,788	87,693	123,560
BPA Appropriation Interest	46,435	40,996	34,252
Corps of Engineers Appropriation Interest	150,745	158,866	148,937
Lower Snake River Comp Plan Interest.	16,470	16,466	16,466
Bureau of Reclamation Appropriation Interest	43,249	43,207	43,158
Subtotal, Interest – Operating Expense	372,687	347,228	366,373
Pension and Post-retirement Benefits	23,200	21,100	18,000
Total, Interest, Pension and Post-retirement Benefits	395,887	368,328	384,373

Outyear Funding Schedule

	(accrued expenditures) (dollars in thousands)			
	FY 2009	FY 2010	FY 2011	FY 2012
Total, Interest, Pension and Post-retirement Benefits	415,383	435,237	450,108	465,071

Operating Expense

Description

Interest expense provides for the payment of interest due on FCRPS debt. This consists of capital investment in FCRPS hydroelectric generating and transmission facilities of Bonneville, the Corps and Reclamation. Investments were financed by Congressional appropriations and Bonneville borrowings from the Treasury. Bonneville repays FCRPS debt through its power sales and transmission services revenues.

Since receiving Treasury borrowing authority in 1974 under the Transmission System Act, all Bonneville borrowing has been at market rates. As of Oct 1, 1996, all of Bonneville's repayment obligations on FCRPS appropriated investment (Corps and Reclamation FCRPS investment and Bonneville investment) financed with appropriations prior to the Transmission System Act that were unpaid as of Sept 30, 1996, were restructured and assigned new current-market interest rates. The Bonneville Appropriations Refinancing Act of 1996 called for resetting (reducing) the unpaid principal of FCRPS appropriations and reassigning (increasing) interest rates. New principal amounts were established as of the beginning of FY 1997 at the present value of the principal and annual interest payments Bonneville would make to the Treasury for these obligations in the absence of the legislation, plus $100 million. The new principal amounts are then assigned new interest rates based on the Treasury yield curve rates prevailing at the end of FY 1996. Bonneville's outstanding repayment obligations on appropriations at the end of FY 1996 were $6.7 billion with a weighted average interest rate of 3.4 percent. The refinancing reduced the principal amount to $4.1 billion with a weighted average interest rate of 7.1 percent. Implementation of the refinancing took place in 1997 after audited actual financial data was available. As called for in the legislation, Bonneville submitted its calculations and interest rate assignments implementing the Bonneville Appropriations Refinancing Act to Treasury for their review and approval. Treasury approved the implementation calculations in July 1997. The Act also calls for all future FCRPS appropriations to be assigned prevailing Treasury yield curve interest rates.

Interest estimates are a direct function of costs of Treasury borrowing to Bonneville, repayment status of outstanding FCRPS investments, and projected additions to FCRPS plant in service. These estimates may change over time depending on forecasted market conditions. The interest cost estimates below include the impact of Bonneville's appropriation refinancing legislation.

Bonneville has been paying its unfunded liability of the Civil Service Retirement System (CSRS) and post-retirement benefits into the General Fund of the Treasury (receipt account 892889) since FY 1998. These payments are consistent with the FY 2001 Administration's budget which assumed Bonneville would prospectively cover the full unfunded liability that accrues in fiscal years after FY 1997 of the Civil Service Retirement and Disability Fund (Disability Fund), the Employees Health Benefits Fund (Health Fund), and the Employees Life Insurance Fund (Insurance Fund) that it had not covered prior to FY 1998. As part of the FY 2001 Administration's Budget, Bonneville assumed its entire CSRS cost recovery would be phased in over a 10-year period, given that wholesale power and transmission rates for Bonneville were contractually frozen until the end of FY 2001 in order to meet competitive market pressures. Bonneville paid $23.2 million in FY 2006 and for the final year of the scheduled 10-year period, $21.1 million is assumed to be recovered by Bonneville through rates and paid into the General Fund of the Treasury in FY 2007. BPA expects to satisfy its prior year commitments for under funded CSRS and post-retirement benefits by FY 2007. Post FY 2007 amounts are unscheduled estimates and may change. Cost estimates include pension and post-retirement benefits for Bonneville and the power-related portion of the Corps, Reclamation, and USFWS.

Capital Transfers

Funding Schedule by Activity

Capital Transfers	FY 2006	FY 2007	FY 2008
	(accrued expenditures) (dollars in thousands)		
BPA Bond Amortization	545,000	96,643	241,419
BPA Bond Amortization dependent on debt optimization	N/A	N/A	147,000
BPA Bond Amortization dependent on net secondary revenues	N/A	N/A	130,000
Reclamation Appropriation Amortization	1,065	684	412
BPA Appropriation Amortization	74,640	93,567	31,466
Corps Appropriation Amortization	76,214	195,647	135,771
Total, Capital Transfers	696,919	386,541	686,068

Outyear Funding Schedule

	FY 2009	FY 2010	FY 2011	FY 2012
	(accrued expenditures) (dollars in thousands)			
Total, Capital Transfers	404,408	518,711	468,451	395,886

Description

This activity conveys funds to the Treasury for repayment of certain FCRPS costs not included in the Associated Project Costs budget. Since capital transfers are cash transactions, they are not considered budget obligations. The total FY 2006 Capital Transfers amount includes $342 million of amortization planned in advance of scheduled amortization, or prepayment of Treasury debt, consistent with BPA's 2007 power rate case documentation. The cumulative amount of actual advance amortization payments as of the end of FY 2006 was about $1,802 million.

This FY 2008 budget assumes amortization payments to the Treasury on BPA’s bond obligations. Amortization estimates, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President’s budget. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and other variables that may affect the opportunity for advanced amortization payments including certain restrictions on the amount of bonds available for BPA pre-payment. Actual associated revenues could vary due to volatility of secondary power markets, streamflow variability, volatility of financial markets effecting ENW debt optimization, and other uncertainties.

BONNEVILLE POWER ADMINISTRATION
TOTAL OBLIGATIONS/OUTLAYS
Current Services
(in millions of dollars) FB 24-Jan-07
FISCAL YEAR

BP-1 SUMMARY	**2006**		**2007**		**2008**		**2009**	**2010**	**2011**	**2012**
1,3/	**Oblig.**	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Oblig.**	**Oblig.**	**Oblig.**
1 Residential Exchange	156	156	337	337	337	337	337	300	300	171
2 Power Services 2/	1,475	1,475	1,565	1,565	1,372	1,372	1,616	1,442	1,508	1,524
3 Transmission Services	425	425	518	518	576	576	562	592	596	618
4 Conservation & Energy Efficiency	83	83	98	98	97	97	97	107	107	108
5 Fish & Wildlife	173	173	179	179	179	179	179	179	179	179
6 Interest/ Pension 4/	396	396	368	368	384	384	415	435	450	465
7 Associated Project Cost - Capital	121	121	133	133	145	145	137	123	124	135
8 Capital Equipment	18	18	33	33	47	47	32	31	26	27
3 Planning Council	9	9	9	9	9	9	9	10	10	10
10 Misc. Accounting Adjs.	0	0	0	0	0	0	0	0	0	0
11 Projects Funded in Advance	48	48	139	139	77	77	77	69	71	64
12 Capitalized Bond Premiums	0	0	0	0	0	0	0	0	0	0
TOTAL OBLIGATIONS/ OUTLAYS 3/	**2,904**	**2,904**	**3,379**	**3,379**	**3,223**	**3,223**	**3,461**	**3,288**	**3,371**	**3,301**

REVENUES AND REIMBURSEMENTS
Current Services
(in millions of dollars)
FISCAL YEAR

BP-1 SUMMARY	**2006**		**2007**		**2008**		**2009**	**2010**	**2011**	**2012**
	Oblig.	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Oblig.**	**Oblig.**	**Oblig.**
13 Revenues 5/	3,742	3,742	3,250	3,250	3,247	3,247	3,506	3,337	3,426	3,354
14 Project Funded in Advance	48	48	139	139	77	77	77	69	71	64
15 **TOTAL**	**3,790**	**3,790**	**3,389**	**3,389**	**3,324**	**3,324**	**3,583**	**3,406**	**3,497**	**3,418**
BUDGET AUTHORITY (NET) 6/	**(511)**		**40**		**(101)**		**(110)**	**(105)**	**(113)**	**(105)**
16 **OUTLAYS (NET) 6,7/**		**(917)**		**(9)**		**(93)**	**(97)**	**(95)**	**(104)**	**(99)**

The accompanying notes are an integral part of this table.

1/ This FY 2008 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2012. The TS capital and expense estimates are based on forecasted Transmission 2006 Rate Case estimates updated for known changes for FY 2007, PIR estimates for FYs 2008-2009, and associated outyear estimates for FYs 2010-2012.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

2/ Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

3/ This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

4/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

5/ Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, however causing the same net outlay result. Adjustments for depreciation and 4(h)(10)(C) are also assumed.

Beginning in FY 2008, revenue estimates in this FY 2008 budget include assumed annual net secondary power revenues that exceed $500 million. Actual net secondary revenues would vary significantly due to many variables affecting BPA's revenues including the volatility of secondary power markets and the variability of annual streamflows.

6/ BPA will receive $49 million of additional budget authority in FY 2007 to accommodate the work necessary to relocate on the radio spectrum consistent with the Commercial Spectrum Enhancement Act (P.L. 108-494). In the subsequent years, per the assumed spend out rates developed as part of BPA' work plans, there will be outlays as the work is performed.

7/ Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that along with actual market conditions will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated net outlay estimates could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

EXPENSED OBLIGATIONS/OUTLAYS 1,4/
Current Services
(in millions of dollars)
FISCAL YEAR

	2006		2007		2008		2009	2010	2011	2012
	Oblig.	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Oblig.**	**Oblig.**	**Oblig.**
1 Residential Exchange	156	156	337	337	337	337	337	300	300	171
2 Power Services 2/	1,475	1,475	1,565	1,565	1,372	1,372	1,616	1,442	1,508	1,524
3 Transmission Services	287	287	291	291	298	298	309	311	315	318
4 Conservation & Energy Efficiency	63	63	66	66	65	65	65	67	67	68
5 Fish & Wildlife	138	138	143	143	143	143	143	143	143	143
6 Interest/ Pension 3/	396	396	368	368	384	384	415	435	450	465
7 Planning Council	9	9	9	9	9	9	9	10	10	10
8 TOTAL EXPENSE	2,524	2524	2779	2779	2608	2608	2894	2708	2793	2699
10 Projects Funded in Advance	48	48	139	139	77	77	77	69	71	64

CAPITAL OBLIGATIONS/OUTLAYS

Current Services

(in millions of dollars)

FISCAL YEAR

BP-2 continued	**2006**		**2007**		**2008**		**2009**	**2010**	**2011**	**2012**
	Oblig.	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Outlays**	**Oblig.**	**Oblig.**	**Oblig.**	**Oblig.**
Conservation & Energy Efficiency	20	20	32	32	32	32	32	40	40	40
11 Transmission Services	138	138	227	227	278	278	253	281	281	300
12 Associated Project Cost	121	121	133	133	145	145	137	123	124	135
13 Fish & Wildlife	35	35	36	36	36	36	36	36	36	36
14 Capital Equipment	18	18	33	33	47	47	32	31	26	27
15 Capitalized Bond Premiums	0	0	0	0	0	0	0	0	0	0
16 **TOTAL CAPITAL INVESTMENTS \5**	**332**	**332**	**461**	**461**	**538**	**538**	**490**	**511**	**507**	**538**
17 **TREASURY BORROWING AUTHORITY TO FINANCE CAPITAL OBLIGATIONS 4,5/**	**332**		**461**		**538**		**490**	**511**	**507**	**538**
18 **TREASURY BORROWING AUTHORITY TO FINANCE OTHER OBLIGATIONS**	**(62)**		**(156)**		**62**		**(61)**	**(70)**	**(100)**	**(289)**
19 **TOTAL TREASURY BORROWING AUTHORITY :**	**270**		**305**		**601**		**429**	**441**	**407**	**249**

The accompanying notes are an integral part of this table.

1/ This FY 2008 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2012. The TS capital and expense estimates are based on forecasted Transmission 2006 Rate Case estimates updated for known changes for FY 2007, PIR estimates for FYs 2008-2009, and associated outyear estimates for FYs 2010-2012.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

2/ Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

3/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

4/ This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

5/ Treasury Borrowing Authority to Finance Other Obligations represents the use of (positive), or building up of (negative), deferred borrowing. Deferred borrowing is created when Bonneville uses cash from revenues to liquidate capital obligations in lieu of Treasury borrowing. This creates the ability in future years to borrow money, when fiscally prudent, to liquidate revenue funded activities. The amount on this line, under the title "Treasury Borrowing Authority to Finance Other Obligations" represents the annual use or creation of deferred borrowing. OMB has requested that Bonneville show this deferred borrowing as a resource carried forward from year to year in the manner displayed here.

CURRENT SERVICES
(in millions of dollars)

CAPITAL TRANSFERS	FISCAL YEAR						
Amortization:	2006 Pymts	2007 Pymts	2008 Pymts	2009 Pymts	2010 Pymts	2011 Pymts	2012 Pymts
20 BPA Bonds	545	97	241	208	120	141	32
20a Increase in BPA Bond dependent on debt optimization	N/A	N/A	147	0	0	0	0
20b Increase in BPA Bond dependent on net secondary revenues	N/A	N/A	130	128	130	128	130
21 Reclamation Appropriations	1	1	0	0	0	0	0
22 BPA Appropriations	75	94	31	14	98	79	169
23 Corps Appropriations	76	196	136	55	171	121	65
24 **TOTAL CAPITAL TRANSFERS**	**697**	**388**	**685**	**405**	**519**	**469**	**396**

STAFFING

	2006	2007	2008	2009	2010	2011	2012
25 **FULL-TIME EQUIVALENT (FTE)**	**2,923**	**3,000**	**3,000**	**3,000**	**3,000**	**3,000**	**3,000**

The accompanying notes are an integral part of this table.

Amortization/Capital Transfer estimates in this budget, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President's budget. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and other variables that may affect the opportunity for advanced amortization payments.

The cumulative amount of actual advance amortization payments as of the end of FY 2006 is $1,802 million.

PROGRAM & FINANCING SUMMARY

Current Services

(in millions of dollars)

Identification Code: 89-4045-0-3-271

		2006	2007	est. 2008	2009	2010	2011	2012
Program by activities:								
	Operating expenses:							
0.01	Power Services	1,229	1,296	1,094	1,329	1,147	1,205	1,212
0.02	Residential Exchange	156	337	337	337	300	300	171
	Associated Project Costs:							
0.05	Bureau of Reclamation	63	72	75	78	80	81	84
0.06	Corps of Engineers	147	162	166	170	177	182	187
0.07	Colville Settlement	17	17	17	18	18	19	19
0.19	U.S. Fish & Wildlife Service	20	19	20	20	21	22	22
0.20	Planning Council	9	9	9	9	10	10	10
0.21	Fish & Wildlife	138	143	143	143	143	143	143
0.23	Transmission Services	287	291	298	309	311	315	318
0.24	Conservation & Energy Efficiency	63	66	65	65	67	67	68
0.25	Interest	373	347	366	385	404	419	433
0.26	Pension and Health Benefits 1/	23	21	18	31	31	31	32
0.91	**Total operating expenses 2/**	**2,525**	**2,780**	**2,608**	**2,894**	**2,709**	**2,794**	**2,699**
	Capital investment:							
1.01	Power Services	121	133	145	137	123	124	135
1.02	Transmission Services	138	227	278	253	281	281	300
1.03	Conservation & Energy Efficiency	20	32	32	32	40	40	40
1.04	Fish & Wildlife	35	36	36	36	36	36	36
1.05	Capital Equipment	18	33	47	32	31	26	27
1.06	Capitalized Bond Premiums	0	0	0	0	0	0	0
1.07	**Total Capital Investment 3/**	**332**	**461**	**538**	**490**	**511**	**507**	**538**
1.08	Misc. Accounting Adjustments	0						
2.01	Projects Funded in Advanced	48	139	77	77	69	71	64
10.00	**Total obligations 4/**	**2,904**	**3,380**	**3,222**	**3,461**	**3,289**	**3,372**	**3,301**

The accompanying notes are an integral part of this table.

1/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

2/ Assumes expense obligations, not accrued expenses.
Power Services includes Fish & Wildlife, Residential Exchange, Planning Council, Conservation & Energy Efficiency and Associated Project Costs which have been shown separately for display purposes.

3/ Assumes capital obligations, not capital expenditures.

4/ This FY 2008 budget includes capital and expense estimates for PS based on forecasted FY 2007 Final Power Rate Proposal and associated outyear estimates for FYs 2010-2012. The TS capital and expense estimates are based on forecasted Transmission 2006 Rate Case estimates updated for known changes for FY 2007, PIR estimates for FYs 2008-2009, and associated outyear estimates for FYs 2010-2012.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

Refer to 16 USC Chapters 12B, 12G, 12H, and BPA's other organic laws, including P.L. 100-371, Title III, Sec. 300, 102 Stat. 869, July 18, 1988 regarding BPA's ability to obligate funds.

Program and Financing (continued)
Current Services
(in millions of dollars)

	2006	2007	est. 2008	2009	2010	2011	2012
Financing:							
21.90 Unobligated balance available, start of year. Treasury balance 5/	(121)	(240)	(240)	(240)	(240)	(240)	(240)
24.40 Unobligated balance available, end of year. Treasury balance 5/	(240)	(240)	(240)	(240)	(240)	(240)	(240)
25.00 Unobligated balance lapsing	0	0	0	0	0	0	0
39.00 **Budget authority (gross)**	**2,904**	**3,429**	**3,243**	**3,473**	**3,301**	**3,384**	**3,313**
Budget Authority:							
61.00 Transfer to other accounts	(69)						
62.00 Transfer from other accounts		49					
66.10 Contract Authority	871						
67.10 Permanent Authority: Authority to borrow from Treasury (indefinite) 6/	270	305	601	429	441	407	249
Spending authority from off-setting collections	3,327	3,389	3,344	3,583	3,406	3,497	3,418
69.47 Portion applied to debt reduction	(565)	(314)	(702)	(438)	(451)	(416)	(259)
69.90 **Spending authority from offsetting collections (adjusted)**	**1,832**	**3,075**	**2,642**	**3,044**	**2,860**	**2,977**	**3,064**
Relation of obligations to outlays:							
71.00 Total obligations	2,904	3,380	3,223	3,461	3,289	3,372	3,301
Obligated balance, start of year:							
72.47 Authority to borrow	617	617	617	617	617	617	617
74.47 Authority to borrow	(617)	(617)	(617)	(617)	(617)	(617)	(617)
87.00 Outlays (gross)	2,410	3,380	3,251	3,473	3,301	3,384	3,313
Adjustments to budget authority and outlays:							
Deductions for offsetting collections:							
88.00 Federal funds	(59)	(90)	(90)	(90)	(90)	(90)	(90)
88.40 Non-Federal sources	(3,268)	(3,299)	(3,254)	(3,493)	(3,316)	(3,407)	(3,328)
88.90 Total, offsetting collections	(3,327)	(3,389)	(3,344)	(3,583)	(3,406)	(3,497)	(3,418)
89.00 **Budget authority (net)**	**(511)**	**40**	**(101)**	**(110)**	**(105)**	**(113)**	**(105)**
90.00 **Outlays (net) 7/**	**(917)**	**(9)**	**(93)**	**(97)**	**(95)**	**(104)**	**(99)**

The accompanying notes are an integral part of this table.

5/ Treasury balance and unobligated balance estimates assume that BPA will borrow from Treasury the amount needed to finance the full capital program. Actual Treasury borrowing and cash balances will be different, depending on net revenues, Treasury interest rates, and other cash management factors. Borrowing could be higher such that cash balances at the end of each year could equal total reserves.

6/ The Permanent Authority: Authority to borrow (indefinite) from Treasury amounts reflect both BPA's capital program financing needs and either the use of, or creation of, deferred borrowing. Deferred borrowing in created when, as a cash and debt management decision, BPA uses cash from revenues to liquidate capital obligations in lieu of borrowing from Treasury. This temporary use of cash on hand instead of borrowed funds creates the ability in future years to borrow money, when fiscally prudent. Technical Executive Branch budget display and tracking requirements have modified the way BPA shows this deferred borrowing as a resource carried forward from year-to-year. This amount must therefore be added to, or subtracted from, BPA's current year Treasury borrowing authority amount, making this number a combination of capital program financing needs and the annual use, or creation of deferred borrowing. The FY 1989 Energy and Water Development Appropriations Act (P.L. 100-371 of 7/19/88) clarified that BPA has authority to incur obligations in excess of Treasury borrowing authority and cash in the BPA Fund. The two amounts which comprise the net amount of line 67.10 above as follows:

	FISCAL YEAR						
Treasury Borrowing Authority:	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
to finance capital obligations	332	461	539	490	511	507	538
to finance other obligations	(62)	(156)	62	(61)	(70)	(100)	(289)
Total Treasury Borrowing Authority (67.10)	**270**	**305**	**601**	**429**	**441**	**407**	**249**

7/ Net Outlay estimates are based on current cost savings to date and anticipated cash management goals. They are expected to follow anticipated management decisions throughout the rate period that along with actual market conditions will impact revenues and expenses. Actual Net Outlays are volatile and are reported in SF-133. Estimated net outlay estimates could change due to changing market conditions, streamflow variability, and continuing restructuring of the electric industry.

Revenues, included in the Net Outlay formulation, are calculated consistent with cash management goals and assume a combination of adjustments. Assumed adjustments include the use of a combination of tools, including upcoming rate adjustment mechanisms, a net revenue risk adjustment, debt service refinancing strategies and/or short-term financial tools to manage net revenues and cash. Some of these potential tools will reduce costs rather than generate revenue, however causing the same net outlay result. Adjustments for depreciation and 4(h)(10)(C) are also assumed.

This budget has been prepared in accordance with the Budget Enforcement Act (BEA) of 1990. Under this Act all BPA budget estimates are treated as mandatory and are not subject to the discretionary caps included in the BEA. These estimates support activities which are legally separate from discretionary activities and accounts. Thus, any changes to BPA estimates cannot be used to affect any other budget categories which have their own legal dollar caps. Because BPA operates within existing legislative authority, BPA is not subject to a Budget Enforcement "pay-as-you-go" test regarding its revision of current-law funding estimates.

BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4A

	Fiscal Year 2006				Fiscal Year 2007			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	1,668	1,668	2,748	2,776	1,624	1,455	2,704	2,481
Plus: Annual Increase								
Annual Increase: 1974 Act	**156**		156		**260**		260	
Annual Increase: 1980 Act	**176**		176		**201**		201	
Cum.-Annual Treasury Borrowing	332	332	332		461	461	461	
Treasury Borrowing (Cash)				250				461
Less:								
BPA Bond Amortization	545	545	545	545	97	97	97	97
BPA Bond Amortization dependent ...on debt optimization								
BPA Bond Amortization dependent ...on net secondary revenues								
Net Increase/(Decrease):	(213)	(213)	(213)	(295)	364	364	364	364
Cum.-End-of-Year: Total	1,624	1,455		2,481	3,089	1,819	3,068	2,845
Total Remaining Treasury Borrowing Amount				1,969				1,605
Total Legislated Treasury Borrowing Amount				4,450				4,450

The accompanying notes are an integral part of this table.

In any given year, BPA may issue less debt than forecast depending on net revenues, Treasury interests rates, and other cash management factors. In such cases, BPA accumulates a deferred borrowing balance that it accesses as necessary in the future.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA Revenue financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2006-2009.

BPA currently estimates joint financing and ownership (lease-purchase excluding financing for Columbia Generating Station (CGS) new investments) at $100 million in FY 2007, $49 million in FY 2008, $50 million in FY 2009, $50 million in FY 2010, $53 million in FY 2011, and $60 million in FY 2012 for an estimated total of $362 million during the period FY 2007 through FY 2012

Amortization/Capital Transfer estimates in this budget, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President's budget. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and other variables that may affect the opportunity for advanced amortization payments.

The cumulative amount of actual advance amortization payments as of the end of FY 2006 is $1,802 million.

BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4B

	Fiscal Year 2008				Fiscal Year 2009			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	1,553	1,819	3,068	2,845	1,850	2,116	3,365	2,865
Plus: Annual Increase								
Annual Increase: 1974 Act	**325**		325		**285**		285	
Annual Increase: 1980 Act	**213**		213		**205**		205	
Cum.-Annual Treasury Borrowing	538	538	538		490	490	490	
Treasury Borrowing (Cash)				538				490
Less:								
Total BPA Bond Amortization	241	241	241	241	208	208	208	208
Total BPA Bond Amortization ...dependent on debt optimization				147				0
BPA Bond Amortization dependent ...on net secondary revenues				130				128
Net Increase/(Decrease):								
Total	297	297	297	20	282	282	282	154
Cum.-End-of-Year: Total	1,850	2,116	3,365	2,865	2,132	2,398	3,647	3,019
Total Remaining Treasury Borrowing Amount				1,585				1,431
Total Legislated Treasury Borrowing Amount				4,450				4,450

The accompanying notes are an integral part of this table.
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Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA Revenue financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2006-2009.

BPA currently estimates joint financing and ownership (lease-purchase excluding financing for Columbia Generating Station (CGS) new investments) at $100 million in FY 2007, $49 million in FY 2008, $50 million in FY 2009, $50 million in FY 2010, $53 million in FY 2011, and $60 million in FY 2012 for an estimated total of $362 million during the period FY 2007 through FY 2012

Amortization/Capital Transfer estimates in this budget, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President's budget. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and other variables that may affect the opportunity for advanced amortization payments.

BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4C

	Fiscal Year							
	2010				**2011**			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	2,132	2,398	3,647	3,019	2,524	2,790	4,039	3,281
Plus: Annual Increase								
Annual Increase: 1974 Act	**313**		313		**307**		307	
Annual Increase: 1980 Act	**199**		199		**200**		200	
Cum.-Annual Treasury Borrowing	512	512	512		507	507	507	
Treasury Borrowing (Cash)				512				507
Less:								
Total BPA Bond Amortization	120	120	120	120	141	141	141	141
Total BPA Bond Amortization dependent on debt optimization				0				0
BPA Bond Amortization dependent on net secondary revenues				130				128
Net Increase/(Decrease):								
Total	392	392	392	262	366	366	366	238
Cum.-End-of-Year: Total	2,524	2,790	4,039	3,281	2,890	3,156	4,405	3,519
Total Remaining Treasury Borrowing Amount				1,169				931
Total Legislated Treasury Borrowing Amount				4,450				4,450

The accompanying notes are an integral part of this table.

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Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA Revenue financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2006-2009.

BPA currently estimates joint financing and ownership (lease-purchase excluding financing for Columbia Generating Station (CGS) new investments) at $100 million in FY 2007, $49 million in FY 2008, $50 million in FY 2009, $50 million in FY 2010, $53 million in FY 2011, and $60 million in FY 2012 for an estimated total of $362 million during the period FY 2007 through FY 2012

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BONNEVILLE POWER ADMINISTRATION
BPA STATUS of TREASURY BORROWING
CURRENT SERVICES
(in millions of dollars)

BP-4D

	Fiscal Year 2012			
	Net Capital Obs	Net Capital Obs Subject to BA	Net Capital Expend.	Bonds Out-Standing
Start-of-Year: Total	2,890	3,156	4,405	3,519
Plus: Annual Increase				
Annual Increase: 1974 Act	**327**		327	
Annual Increase: 1980 Act	**211**		211	
Cum.-Annual Treasury Borrowing	538	538	538	
Treasury Borrowing (Cash)				538
Less:				
Total BPA Bond Amortization	32	32	32	32
Total BPA Bond Amortization dependent on debt optimization				0
BPA Bond Amortization dependent on net secondary revenues				130
Net Increase/(Decrease):				
Total	506	506	506	376
Cum.-End-of-Year: Total	3,396	3,662	4,911	3,895
Total Remaining Treasury Borrowing Amount				555
Total Legislated Treasury Borrowing Amount				4,450

The accompanying notes are an integral part of this table.

In any given year, BPA may issue less debt than forecast depending on net revenues, Treasury interests rates, and other cash management factors. In such cases, BPA accumulates a deferred borrowing balance that it accesses as necessary in the future.

Capital funding levels also reflect BPA's Capital Planning Review Process and external factors such as the significant changes affecting the West Coast power and transmission markets, along with planned infrastructure investments designed to address the long-term needs of the region. Capital investment levels in this FY 2008 budget have been updated to reflect executive management decisions from BPA's cross-agency Capital Allocation Board.

Budget estimates included in this budget are subject to change due to rapidly changing economic and institutional conditions in the evolving competitive electric utility industry.

BPA Revenue financing of $15 million annually is assumed as part of TS capital-PFIA for FYs 2006-2009.

BPA currently estimates joint financing and ownership (lease-purchase excluding financing for Columbia Generating Station (CGS) new investments) at $100 million in FY 2007, $49 million in FY 2008, $50 million in FY 2009, $50 million in FY 2010, $53 million in FY 2011, and $60 million in FY 2012 for an estimated total of $362 million during the period FY 2007 through FY 2012

Amortization/Capital Transfer estimates in this budget, based on existing rate case plans and estimated amortization for future rate case periods, are adjusted to reflect, beginning in FY 2008, advance amortization payments dependent on an equivalent amount of assumed net secondary revenues over $500 million and anticipated debt optimization refinancing of ENW obligations in FY 2008, consistent with the President's budget. These estimates may change due to revised capital investment plans, actual Treasury borrowing, and other variables that may affect the opportunity for advanced amortization payments.

Bonneville's goal is to preserve the use of existing borrowing authority through at least FY 2018. Through a combination of debt management tools such as third party financing, debt optimization and assumed extension of third party financing and other actions beyond FY 2012, BPA estimates that existing borrowing authority could remain available through the end of FY 2016.

TREASURY PAYMENTS

(in millions of dollars)

		FISCAL YEAR						
		2006	2007	2008	2009	2010	2011	2012
A.	**INTEREST ON BONDS & APPROPRIATIONS**							
	Bonneville Bond Interest							
1	Bonneville Bond Interest (net)	116	88	124	151	172	199	226
2	AFUDC [1/]	17	17	18	19	19	19	19
	Appropriations Interest							
3	Bonneville	46	41	34	32	31	24	18
4	Corps of Engineers [2/]	151	159	149	142	142	137	132
5	Lower Snake River	16	16	16	16	16	16	16
6	Bureau of Reclamation [3/]	43	43	43	43	43	43	40
7	**Total Bond and Approp. Interest**	**389**	**364**	**384**	**403**	**423**	**438**	**451**
B.	**ASSOCIATED PROJECT COST**							
8	Bureau of Reclamation Irrigation Assistance	1	0	3	7	0	0	1
9	Bureau of Rec. O & M [4/]	1	0	0	0	0	0	0
10	Corps of Eng. O & M [4/]	2	0	0	0	0	0	0
11	L. Snake River Comp. Plan O & M [4/]	0	0	0	0	0	0	0
12	**Total Assoc. Project Costs**	**4**	**0**	**3**	**7**	**0**	**0**	**1**
C.	**CAPITAL TRANSFERS**							
	Amortization							
13	Bonneville Bonds	545	97	241	208	120	141	32
13a	BPA Bond Amortization dependent on ..debt optimization	0	0	147	0	0	0	0
13b	BPA Bond Amortization dependent on ...net secondary revenues	0	0	130	128	130	128	130
14	Bureau of Reclamation Appropriations	1	1	0	0	0	0	0
15	Corps of Engineers Appropriations	76	196	136	55	171	121	65
16	Lower Snake River Comp. Plan	0	0	0	0	0	0	0
17	Bonneville Appropriations	75	94	31	14	98	79	169
	Total Capital Transfers [5/]	**697**	**388**	**685**	**405**	**519**	**469**	**396**
D.	**OTHER PAYMENTS**							
18	Unfunded CSRS Liability [6/]	23	21	18	31	31	31	32
21	**TOTAL TREASURY PAYMENTS [7/]**	**1,113**	**773**	**1,090**	**846**	**973**	**938**	**880**

The accompanying notes are an integral part of this table.

1/ This interest cost is capitalized and included in BPA's Transmission System Development, System Replacments, and Associated Projects Capital programs. AFUDC is financed through the sale of bonds.

2/ Includes interest on construction funding for Corp of Engineers (Corps) fish bypass facilities at Corps dams in the Columbia River Basin, including Lower Monumental, Ice Harbor, and The Dalles.

3/ Includes payments paid by Reclamation to Treasury on behalf of Bonneville.

4/ Costs for power O&M is funded directly by Bonneville as follows (in millions)

FISCAL YEAR	2006	2007	2008	2009	2010	2011	2012
Bureau of Reclamation	63	72	75	78	80	81	84
Corps of Engineers	147	162	166	170	177	182	187
Subtotal Bureau and Corps	210	234	241	248	257	263	271
Lower Snake River Comp. Plan	20	19	20	20	21	22	22
Total	230	253	261	268	278	285	293

Reclamation O&M budget estimates do not reflect approximately $10 million in Reclamation cost savings of which $3 million can be spent in a single fiscal year. Corps O&M budget estimates do not reflect approximately $1.5 million in Corps cost savings.

Bonneville also directly funds the Corps up to $9.7 million annually and the Reclamation up to $3 million annually for small capital power O&M items. Funding for these small capital power items is included within the PS capital budget.

5/ BPA Amortization/Capital Transfers for FY 2006 includes final payment to Treasury for reimbursement of judgment funds, consistent with the Enron settlement agreement in 2003.

6/ See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

7/ Does not include Treasury bond premiums on refinanced Treasury bonds.

OBJECT CLASSIFICATION STATEMENT
(in millions of dollars) 1/

IDENTIFICATION CODE: 89-4045-0-3-271
DIRECT OBLIGATIONS

ESTIMATES

		2006	2007	2008
11.1	Full-time permanent	217	253	260
11.3	Other than full-time permanent			
11.5	Other personnel compensation	36	42	42
11.9	**Total personnel compensation**	**253**	**295**	**302**
12.1	Civilian personnel benefits	56	65	65
21.0	Travel and transportation of persons	13	15	15
22.0	Transportation of things	3	3	3
23.1	Rental payments to GSA			
23.2	Rents, other	53	62	61
23.3	Communication, utilities & misc. charges	6	7	7
24.0	Printing and reproduction			
25.1	Consulting Services			
25.2	Other Services	1,737	2,023	1,868
25.3	Purchases from Government Accounts			
25.4	O&M of Facilities			
25.5	R & D Contracts	11	11	9
26.0	Supplies and materials	77	90	89
31.0	Equipment			
32.0	Lands and structures	38	44	44
41.0	Grants, subsidies, contributions	58	68	67
43.0	Interest and dividends	599	697	693
99.0	**Total obligations**	**2,904**	**3,380**	**3,223**

Includes object classifications developed from updated GL accounting codes consistent with implementation of BPA's business enterprise system of accounts. The object classifications are subject to change as BPA's GL accounting codes continue to evolve to more effectively meet management information needs, and meet FERC and Federal reporting requirements.

Estimate of Proprietary Receipts
(in millions of dollars)

	Fiscal Year						
	2006	2007	2008	2009	2010	2011	2012
Reclamation Interest	43	43	43	43	43	43	40
Reclamation Amortization	1	1	0	0	0	0	0
Reclamation O&M	1	0	0	0	0	0	0
Reclamation Irrig. Assist.	1	0	3	7	0	0	1
Revenues Collected by Reclamation Distributed in Treasury Account (credit)	-10	-7	-7	-7	-7	-7	-7
Colville Settlement (credit)	-5	-5	-5	-5	-5	-5	-5
Total 1/ Reclamation Fund	**31**	**32**	**34**	**38**	**31**	**31**	**29**
Corps O&M	2						
CSRS	23	21	18	31	31	31	31
Total 2/ Repayments on misc.costs	**25**	**21**	**18**	**31**	**31**	**31**	**31**

1/ Includes amortization of appropriations and irrigation assistance, and interest costs for Reclamation. The cost of power O&M for Reclamation is no longer included in Proprietary Receipts due to Direct Funding by Bonneville. Represents transfer to Account #895000.26

2/ The costs of power O&M for the Corps and Lower Snake Comp. Plan are no longer included in Proprietary Receipts due to Direct Funding by Bonneville. Represents transfers to Account #892889, Repayments on misc. recoverable costs, not otherwise classified. Costs for power O&M is funded directly by Bonneville as follows (in millions)

	2006	2007	2008	2009	2010	2011	2012
Bureau of Reclamation	63	72	75	78	80	81	84
Corps of Engineers	147	162	166	170	177	182	187
Lower Snake River Comp. Plan	20	19	20	20	21	22	22

Reclamation O&M budget estimates do not reflect approximately $10 million in Reclamation cost savings of which $3 million can be spent in a single fiscal year. Corps O&M budget estimates do not reflect approximately $1.5 million in Corps cost savings.

Bonneville also directly funds the Corps up to $9.7 million annually and the Reclamation up to $3 million annually for small capital power O&M items. Funding for these small capital power items is included within the PS capital budget.

See Interest Expense, Pension and Post-retirement Benefits and Capital Transfers section of this budget for a complete discussion of these cost estimates.

BONNEVILLE POWER ADMINISTRATION

FISH AND WILDLIFE COSTS [1/ 2/]

COST ELEMENT	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
CAPITAL INVESTMENTS 1/										
BPA FISH AND WILDLIFE	28.1	22.0	14.7	13.9	16.5	6.1	11.6	8.5	12.2	35.4
ASSOCIATED PROJECTS (FEDERAL HYDRO)	(42.6)	-	14.1	47.0	6.2	8.8	68.4	75.9	53.8	360.9
BPA DIRECT FISH AND WILDLIFE PROGRAM	82.2	104.9	108.2	108.2	101.1	137.1	140.7	137.9	135.8	137.9
SUPPLEMENTAL MITIGATION PROGRAM EXPENSES					2.9	7.1	6.5	7.8	0.0	0.0
REIMBURSABLE/DIRECT-FUNDED PROJECTS										
O & M LOWER SNAKE RIVER HATCHERIES	11.8	11.4	13.0	12.4	12.7	14.9	15.1	17.3	17.2	20.1
O & M CORPS OF ENGINEERS	18.9	18.5	19.9	19.7	23.1	28.2	30.3	32.3	32.5	31.8
O & M BUREAU OF RECLAMATION	1.5	2.7	2.6	1.8	3.0	3.8	3.1	3.9	3.9	4.5
OTHER (NW POWER AND CONSERVATION COUNCIL)	3.7	3.7	3.4	3.7	3.7	4.0	4.0	3.7	4.3	4.3
SUBTOTAL (REIMB/DIRECT-FUNDED)	35.9	36.4	38.9	37.6	42.5	50.9	52.6	57.2	57.9	60.7
TOTAL OPERATING EXPENSES	**118.1**	**141.3**	**147.1**	**145.8**	**146.5**	**195.1**	**199.8**	**202.9**	**193.7**	**198.6**
PROGRAM RELATED FIXED EXPENSES										
INTEREST EXPENSE	52.4	48.9	49.4	48.4	49.1	48.5	49.9	53.3	56.4	53.4
AMORTIZATION EXPENSE	12.4	14.1	15.3	16.1	16.8	17.2	17.4	17.5	17.4	17.4
DEPRECIATION EXPENSE	11.5	11.1	11.4	11.8	12.3	12.5	13.2	14.6	15.9	16.7
TOTAL FIXED EXPENSES	**76.3**	**74.1**	**76.1**	**76.3**	**78.2**	**78.2**	**80.5**	**85.4**	**89.7**	**87.5**
GRAND TOTAL PROGRAM EXPENSES	**194.4**	**215.4**	**223.2**	**222.1**	**224.7**	**273.3**	**280.3**	**288.3**	**283.4**	**286.1**
FORGONE REVENUES AND POWER PURCHASES										
FOREGONE REVENUES	107.8	116.5	197.8	193.1	115.9	12.6	79.2	21.7	182.1	397.4
BPA POWER PURCH. FOR FISH ENHANCEMENT	-	5.4	47.6	64.8	1,389.6	147.8	171.1	191.0	110.8	168.2
TOTAL FOREGONE REVENUES AND POWER PURCHASES	**107.8**	**121.9**	**245.4**	**257.9**	**1,505.5**	**160.4**	**250.3**	**212.7**	**292.9**	**565.6**
PROGRAM EXPENSES, FOREGONE REVENUES, & POWER PURCHASES	**302.2**	**337.3**	**468.6**	**480.0**	**1,730.2**	**433.7**	**530.6**	**501.0**	**576.3**	**851.7**
CREDITS										
4(h)(10)(C) credits earned	(29.7)	(35.7)	(46.0)	(50.4)	(336.6)	(66.4)	(73.6)	(77.0)	(57.7)	(76.4)
FISH COST CONTINGENCY FUND	-	-	-	-	(246.5)	-	(78.7)	-	-	0.0
TOTAL CREDITS	**(29.7)**	**(35.7)**	**(46.0)**	**(50.4)**	**(583.1)**	**(66.4)**	**(152.3)**	**(77.0)**	**(57.7)**	**(76.4)**

1/ These are audited actual costs reported on an accrual basis

2/ For purposes of this presentation, this financial information has been made publicly available by BPA in February 2007 and is consistent with the financial system of record used in preparation of the audited financial statements for the respective period reported.

Capital Investments include both BPA's direct Fish and Wildlife Program capital investments, funded by BPA's Treasury borrowing, and "Associated Projects", which include capital investments at the Corps and Reclamation projects, funded by appropriations and repaid by BPA. The negative amount in FY 1997 reflects a decision to reverse "plant-in-service" investment that was never actually placed into service. The annual expenses associated with these investments are included in "Program-Related Fixed Expenses", below.

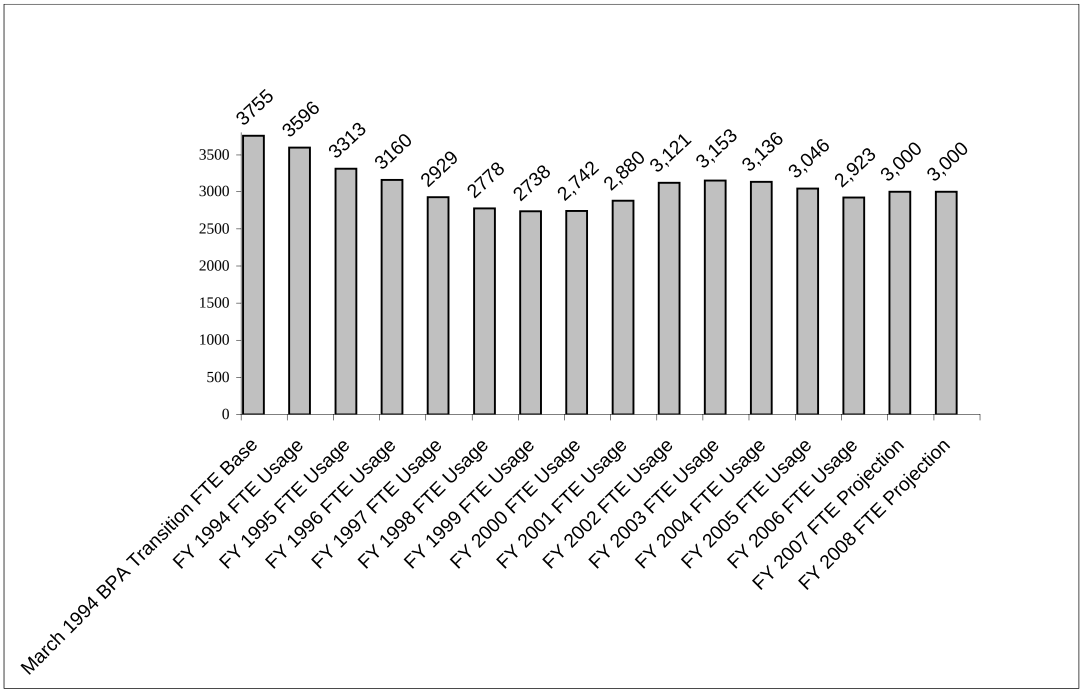
Supplemental Mitigation Program Expenses includes High Priority and Action Plan Expenses and other supplemental programs including power contribution to Pikeminnow reward program

Reimbursable/Direct-Funded Projects includes the portion of costs BPA pays to or on behalf of other entities that is determined to be for fish and wildlife purposes.

Fixed Expenses include depreciation and interest on investment on the Corps projects, and amortization and interest on the investments associated with BPA's direct Fish and Wildlife Program.

The Fish Contingency Fund was exhausted in 2003

BONNEVILLE FTE
(revised January 2007)



BPA has utilized the following number of Voluntary Separation Incentives (VSIs): 190 in FY 1994, 240 in FY 1995, 137 in FY 1996, 135 in FY 1997, 121 in FY 1998, 81 in FY 1999, 43 in FY 2000, 12 in FY 2001, 0 in FY 2002, 80 in FY 2003, 0 in FY 2004, 98 in 2005, and 35 in FY 2006.

BPA continues to assume various authorities, including the use of voluntary separation incentives (VSI) and voluntary early retirement authority (VERA) to help achieve BPA planning levels.

Actual FTE data is consistent with DOE personnel reports.

FTE outyear data are estimates and may change.

Commercial Spectrum Enhancement Act

On December 23, 2004, President Bush signed into law the Commercial Spectrum Enhancement Act (CSEA, title II of P.L. 108-494) that created the Spectrum Relocation Fund (SRF) to provide a centralized and streamlined funding mechanism through which Federal agencies can recover the costs associated with relocating their radio communications systems from certain spectrum bands, which were authorized to be auctioned for commercial purposes. The CSEA appropriated such sums as are required for relocation costs, which are financed by auction proceeds.

On September 18, 2006, the Federal Communications Commission (FCC) concluded an auction of licenses for Advanced Wireless Services (AWS), on radio spectrum in the 1710 megahertz (MHz) to 1755 MHz band that is presently used by Federal agencies, which was paired with the 2110 MHz to 2155 MHz band in the auction. The 1710 MHz to 1755 MHz band of spectrum was relocated to AWS under the provisions of the CSEA, including the use of the SFR to facilitate relocation of Federal communications systems, while the 2110 MHz to 2155 MHz band was reallocated to AWS by the FCC and does not require relocation of Federal systems. The AWS auction raised $13.7 billion in net winning bids, and will facilitate the provision of innovative new wireless services to the commercial market.

In FY 2007, in accordance with Section 204 of the CSEA, the transfer of funds from the SRF to agencies for relocation activities will proceed after the Director of OMB, in consultation with the NTIA, has determined the cost and timelines of relocation the activities. In addition, the CSEA required that transfers may not be made until 30 days after the Director of OMB has notified the Congress of how the SRF will be used to pay relocation costs and the timeline for such relocation activities. Congress will be provided annual updates on the progress of all spectrum relocation activities following the initial transfer of funds.

The total estimate for relocation or modification costs for DOE's radio communications systems in the 1710-1755 MHz band for FY 2007 is $176.8 million. This total represents estimated costs to relocate 36 systems and 168 frequency assignments to support the systems being relocated as detailed below. The estimated unit cost for a particular fixed microwave system is dependent on such variables as the number of radios and towers that need replacement or modification, and the time of year relocation work occurs.

DOE estimates that the timeline for relocating its electric grid command and control system is between 2 and 6 years from the date of the agency's receipt of relocation funds. The table below provides cost estimates for each system that will be relocated.

DOE PROGRAM	COST ($ in millions)	TIME (in months)	NUMBER OF SYSTEMS
NNSA	$ 10.9	36	15
SWPA	$ 8.1	24	1
WAPA	$ 108.2	36	6
BPA	$ 48.7	72	14
OCIO	$ 1.0	72	Administration
TOTAL	**$ 176.8**	**N/A**	**36**