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FEDERAL ELECTRICITY ACTIVITIES

Appendixes to The Federal Government's Net Cost and Potential for Future Losses

Volume 2

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Preface

This volume provides the appendixes to our report, Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses, Volume 1. It contains background information on the federal entities included in our review: the Department of Agriculture's Rural Utilities Service (RUS); four power marketing administrations of the Department of Energy—the Southeastern Power Administration, the Southwestern Power Administration, the Western Area Power Administration, and the Bonneville Power Administration; and the Tennessee Valley Authority. This volume also (1) contains a detailed explanation of our objectives, scope, and methodology in carrying out this review, (2) provides additional information on the likelihood of future losses to the federal government from the electricity-related activities of these entities, and (3) provides further details on the federal government's net costs related to these activities. The 14 appendixes in this volume are organized as follows:

- Appendix I contains background information on the entities and the status of deregulation and competition in the electric power industry.
- Appendix II contains our objectives, scope, and methodology.
- Appendix III provides information on our use of average revenue per kilowatthour to assess competitiveness.
- Appendix IV provides further details on the entities' net costs.
- Appendix V provides additional information on RUS' financing costs.
- Appendixes VI through IX provide additional information on the likelihood that the federal government will incur future losses due to these entities.
- Appendixes X through XIII contain the written comments on a draft of this report from each of these entities.
- Appendix XIV lists the major contributors to this report.

If you have any questions concerning this review, please call me at (202) 512-8341 or Gregory D. Kutz, Associate Director, Governmentwide Audits, at (202) 512-9505.

Linda M. Calbom

Linda M. Calbom
Director, Civil Audits

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Abbreviations

AEAN	aggregate entry age normal
APPA	American Public Power Association
ASCC	Alaska Systems Coordinating Council
BPA	Bonneville Power Administration
CBO	Congressional Budget Office
CFTE	contractor full-time equivalent

CWIP	construction work-in-progress
CSRS	Civil Service Retirement System
CVP	Central Valley Project
CVPIA	Central Valley Project Improvement Act
DOE	Department of Energy
DOJ	Department of Justice
ECAR	East Central Area Reliability Coordination Agreement
EIA	Energy Information Administration
EPAct	Energy Policy Act of 1992
ERCOT	Electric Reliability Council of Texas
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FERS	Federal Employee Retirement System
FFB	Federal Financing Bank
FTE	full-time equivalent
GAAP	generally accepted accounting principles
G&T	generation and transmission
IOU	investor-owned utility
IPP	independent power producer
kWh	kilowatthour
KPMG	KPMG Peat Marwick
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MOA	memorandum of agreement
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission
OMB	Office of Management and Budget
OPM	Office of Personnel Management
O&M	operations and maintenance
PMA	power marketing administration
POG	publicly owned generating utility
PP&E	property, plant and equipment
PURPA	Public Utilities Regulatory Policies Act of 1978
RDA	Rural Development Administration
REA	Rural Electrification Administration
RUS	Rural Utilities Service
SERC	Southeastern Electric Reliability Council
SEPA	Southeastern Power Administration
SFAS	Statement of Financial Accounting Standards

SFFAS	Statement of Federal Financial Accounting Standards
SPP	Southwest Power Pool
SWPA	Southwestern Power Administration
TVA	Tennessee Valley Authority
UKW	Urbach Kahn & Werlin
USDA	United States Department of Agriculture
WAPA	Western Area Power Administration
WPPSS	Washington Public Power Supply System
WSCC	Western Systems Coordinating Council

Background

The electricity industry is changing in response to the regulatory environment and the advent of competition. As discussed in volume 1 and the related appendixes in this volume, the federal government will be affected by these changes because of its involvement in the electric power industry. Several federal government entities are directly or indirectly involved in electricity generation, transmission, and distribution. They include the Rural Utilities Service, the five federal power marketing administrations, and the Tennessee Valley Authority.[1]

Legislative Changes Create a Competitive Electricity Market

Historically, investor-owned utilities (IOUs) and other electricity providers have operated as regulated monopolies. Under traditional utility regulations, IOUs were generally required to provide electric service to all customers within their power service area, and their rates were regulated by state public utility commissions. In exchange, they received exclusive service areas. To serve their customers, IOUs could incur costs for building new generating plants and operating the power system. Regulators generally allowed rates to be set to guarantee IOUs full recovery of their prudently incurred costs plus a regulated profit or rate of return.

However, the electric utility industry has been in the process of transformation, with moves toward deregulation and competition being major factors in this transformation. Deregulation will impact the industry's three major segments: generation, dealing with the production of electricity; transmission, involving moving bulk electricity from the generation plant; and distribution, the process of delivering the power to the retail consumer. An electric utility usually controls all three segments within its service area.

The generation segment has been affected by improvements in technology, which have reduced both the cost of generating electricity as well as the size of generating facilities. Prior preference for large-scale—often nuclear or coal-fired—power plants has been supplanted by a preference for small-scale production facilities, such as cogenerating plants[2] or small natural-gas-fired generation units, that can be brought on-line more quickly and cheaply, with fewer regulatory impediments. According to 1994 studies of utility best practices, primary actions taken by utilities to

[1]Additionally, many of the federal hydroelectric dams that generate power were built and are operated by the Corps of Engineers or the Bureau of Reclamation. Other federal players involved in electricity generation, transmission, and distribution include the Bureau of Indian Affairs under the Department of the Interior and the International Boundary and Water Commission under the State Department.

[2]The cogeneration of power involves the use of steam, waste heat, or resultant energy from a commercial or industrial plant or process for generating electricity.

satisfy demand are either adding small gas-fired combustion units or purchasing power.[3] These sources are less capital intensive and more flexible resources for satisfying changing demand. Gas-fired plants can be built in relatively small megawatt increments (for example, 50-150 megawatts), at perhaps one-quarter of the cost of larger power plants. In 1995, almost half of all new generating capacity starting commercial operation was gas-fired, 99 percent of which was either gas turbine or combined cycle units.

The generation segment of the industry has further been affected by changes in legislation. The Public Utilities Regulatory Policies Act of 1978 (PURPA) facilitated the creation of small (less than 80 megawatts of capacity) electricity generators that were exempt from many state and federal regulations. Called "nonutility generators" or "independent power producers" (IPPs),[4] these entities typically use the newer technologies to generate power. The creation of IPPs and their use of newer technologies have lowered the entry barriers to electricity generation and permitted IPPs to build profitable facilities. IPPs may pose a threat to more traditional utilities because they can build generation facilities near large industrial or municipal customers and generally may be able to generate power at a lower cost than the established utility. The Electric Power Supply Association[5] estimated that at the end of 1995, IPPs accounted for about 9 to 10 percent of the total generating capacity in the United States, directly competing with utility-owned capacity and placing downward pressures on electricity rates.

The transmission segment of the industry has also undergone major changes due to legislative changes. The Energy Policy Act of 1992 (EPAct) promoted increased wholesale competition by allowing wholesale electricity customers, such as municipal distributors, to purchase electricity from any supplier, even if that power must be transmitted over lines owned by another utility. This transmission of electricity across transmission lines of another utility is referred to as wheeling of power. Under the act's provisions, the Federal Energy Regulatory Commission

[3] 1994 Electric Utility Outlook, Washington International Energy Group (Washington, D.C., January 1994) and Issues and Trends Briefing Paper: 18 Key Trends Affecting the Electric Utility Industry, Edison Electric Institute (Washington, D.C., May 1994).

[4] IPPs are not considered utilities because they do not produce power for a service area and do not engage in transmitting or distributing power.

[5] The Electric Power Supply Association is a trade association representing many nonutility generators of electricity and IPPs.

(FERC)[6] can generally compel a utility to transmit (wheel) electricity generated by another utility into its service area for resale. Fees, which are regulated by FERC, are paid to the transmitting utility for the use of its transmission system.

On April 24, 1996, FERC issued Orders 888 and 889 to implement EPAct. FERC Order 888 was key to the growth of wholesale (sales for resale) competition because it provided a framework under which such competition could flourish. In issuing its final rules, FERC concluded that the rules would “remedy undue discrimination in transmission services in interstate commerce and provide an orderly and fair transition to competitive bulk power markets.” At the time the rules were issued, FERC estimated that the rules would result in an annual cost savings of $3.8 billion to $5.4 billion. FERC also expected other nonquantifiable benefits, including better use of existing institutions and assets, new market mechanisms, technical innovation, and less rate distortion.

As a result of PURPA and EPAct, and as provided for under FERC 888, wholesale competition is becoming a reality today throughout the country.[7] As a result, many IOUs have set up power marketing arms (power marketers and power brokers)[8] that are buying and selling excess power across the country. According to industry sources, the number of power marketers registered in the United States increased from 60 to 284 from January 1995 to February 1997—an increase of over 370 percent.

With the advent of wholesale competition, pressure is growing to open the distribution segment of the industry to allow retail competition as well as to allow generating companies or utilities to sell directly to final customers in the franchise area of a different utility while paying regulated rates to use the utilities’ existing transmission and distribution lines. Just as wholesale wheeling under EPAct opened competitors’ transmission systems for wholesale competition, retail competition would require open access to a competitor’s distribution system for the purpose of selling power to individual retail customers.

[6]FERC is an independent agency within the Department of Energy with broad regulatory authority over the interstate transmission and sale of wholesale electricity, natural gas, and oil.

[7]TVA, for the most part, is exempt from the wheeling provisions of the Energy Policy Act of 1992 and therefore does not have to allow competitors to use its transmission lines to sell power to TVA’s customers. This allows TVA’s service area to remain insulated from wholesale competition.

[8]Power marketers take title to electric energy before resale. Power brokers, on the other hand, do not take title and are limited to matching buyers with sellers.

Retail competition is taking shape on a state-by-state basis. California became one of three states in 1996 to pass laws deregulating electric utilities. Beginning January 1, 1998, all of California's retail customers will be able to choose their electricity suppliers. This change not only affects California's current electricity suppliers, but also opens the door for other companies hoping to sell power to California consumers. Regulatory commissions in 44 states and the District of Columbia had adopted or were evaluating deregulation alternatives as of June 30, 1996. Issues relating to retail wheeling are also being addressed by the Congress.

In many industries, competition has been shown to result in lower costs. In the airline industry, we reported that average fare per passenger mile was between 8 percent and 11 percent lower in 1994 than in 1979, while the overall quality of air service at airports has increased.[9] As early as 1986, one study found that increased competition arising from airline deregulation has resulted in a savings for travelers of at least $6 billion annually in reduced fares.[10] In the first 10 years after the telecommunications industry was restructured, prices for long distance telephone services dropped by 66 percent, while over the same period prices for regulated local telephone service rose 13 percent. Similarly, since the natural gas industry was restructured during the 1980s, prices for industrial gas users dropped 52 percent, and residential rates dropped 10 percent (although most residential customers still buy gas from regulated local distribution companies).[11] Savings in the gas industry have been placed at $90 billion over the last 10 years.[12]

Stranded Costs

In deregulating the electricity industry, several key issues need to be resolved, including who will pay for stranded costs. Although definitions vary, stranded costs cannot be recovered through rates even though the utilities incurred those costs to serve their customers with the understanding that regulatory commissions would allow the costs to be recovered through electric rates. For example, a utility may have built facilities or entered into long-term fuel or purchased power supply

[9]Airline Deregulation: Changes in Airfares, Service, and Safety at Small, Medium-Sized, and Large Communities (GAO/RCED-96-79, April 1996).

[10]Steven Morrison and Clifford Winston, The Economic Effects of Airline Deregulation, (Washington, DC.: The Brookings, 1986).

[11]"The Case for Retail Wheeling." Energy, Volume XX, Issue 5, (1995), pp. 9-12. This article was excerpted from Peter C. Christensen, Retail Wheeling: A Guide for End-users, (Tulsa, Oklahoma: Penn Well Publishing Co., 1995).

[12]Patrick Crow, "Electric Restructuring," Oil & Gas Journal, Vol. 95, Issue 11 (March 17, 1997), p. 32.

contracts with the reasonable expectation that its customers would renew their contracts and would pay their share of long-term investments and other incurred costs. Accordingly, if the customer obtains another power supplier or is no longer willing to pay the full costs incurred to provide a service, the utility may be unable to recover those costs and thus would have stranded costs. Estimates of the U.S. industry's total stranded costs range from $10 billion to $500 billion, with $135 billion commonly cited as a reasonable estimate. Although stranded costs are one of the most contentious issues associated with deregulation, FERC has determined that at the wholesale level, stranded costs should be paid by electric customers desiring to exit a system built to serve them.

The following sections provide additional background information on the federal entities involved in electricity generation, transmission, and distribution that are discussed in this report.

The Rural Utilities Service

The U.S. Department of Agriculture (USDA) is the federal government's principal provider of loans used to assist the nation's rural areas in developing their utility infrastructure. Through the Rural Utilities Service (RUS), USDA finances the construction, improvement, and repair of electrical, telecommunications, and water and waste disposal systems. RUS provides credit assistance through direct loans and through repayment guarantees on loans made by other lenders. Established by the Federal Crop Insurance Reform and the Department of Agriculture Reorganization Act of 1994, RUS administers the electricity and telecommunications programs that were operated by the former Rural Electrification Administration (REA) and the water and waste disposal programs that were operated by the former Rural Development Administration (RDA). In this report we will only discuss the electricity segment of RUS' overall utility loan program.[13]

Although operating somewhat like a commercial lender for rural utilities, RUS is not required or intended to recover all of its financing or other costs. RUS' primary function is to provide credit assistance to aid in rural development. Interest charges to its borrowers cover only a portion of the federal government's cost for RUS' electricity loan programs.

[13]The Rural Electrification Act of 1936, as amended (7 U.S.C. 901 et seq.), provides the basic statutory authority for the electricity and telecommunications programs, including the authority for loans to be made by the Federal Financing Bank.

RUS' Electricity Loan Programs

RUS makes direct loans primarily to construct and maintain electricity distribution facilities that provide electricity to rural users. RUS makes direct loans at below-market interest rates according to law. For these loans, it receives annual appropriations to cover the interest differential. It also receives an appropriation to cover its administrative expenses. Loans from the Federal Financing Bank (FFB) are made at Treasury's cost of money plus one-eighth of 1 percent.

RUS electricity loans are made primarily to rural electric cooperatives; more than 99 percent of the borrowers with electricity loans are nonprofit cooperatives. These cooperatives are either Generation and Transmission (G&T) cooperatives or distribution cooperatives. A G&T cooperative is a nonprofit rural electric system whose chief function is to sell electric power on a wholesale basis to its owners, who consist of distribution cooperatives and other G&T cooperatives. A distribution cooperative sells the electricity it buys from a G&T cooperative to its owners, the retail customers. RUS has 55 G&T borrowers (see figure I.1) and 782 distribution borrowers located throughout the country with outstanding electricity loans.

Figure I.1: RUS G&T Borrowers

Note: These RUS borrower identification codes designate the respective locations of the 55 RUS G&T borrowers' headquarters.

Source: GAO analysis of data provided by RUS.

Some RUS loans are at below market interest rates. The following are the types of loans provided in the electricity program:

- Hardship rate loans: Direct loans with a 5 percent interest rate. These loans, referred to as hardship rate loans, are made to borrowers that serve financially distressed rural areas.
- Municipal rate loans: Direct loans with interest rates that are tied to an index of municipal borrowing rates. These loans have a maximum interest rate of 7 percent when the borrower meets, at the time of loan approval, either a consumer density test or both an electricity rate disparity test and a consumer income test. If these tests are not met, the interest rate may exceed 7 percent.
  - Consumer density test: The borrower's total electric system has to have an average of less than 5.5 consumers per mile of line.
  - Rate disparity test: The borrower's average revenue per kilowatthour sold has to be more than the average revenue per kilowatthour sold by all electric utilities in the state in which the borrower provides service.
  - Consumer income test: Either the average per capita income of the residents receiving electric service from the borrower has to be less than the average per capita income of residents of the state in which the borrower provides service or the median household income of the households receiving electric service from the borrower has to be less than the median household income of the households in the state.
- Direct FFB lending: RUS is required to make 100 percent loan repayment guarantees for any loans made to rural utility borrowers through FFB. FFB loans have an interest rate that is the Treasury's cost of money plus one-eighth of 1 percent.

In addition to providing direct loans, RUS also guarantees repayment of loans for rural utilities made by commercial banks—RUS guarantees 100 percent of loans from qualified lenders. However, RUS has not guaranteed any loans from commercial banks in recent years because all applicants have applied for loans made by the FFB, which offers Treasury's interest rate plus one-eighth of 1 percent.

RUS' Loan Obligations

At September 30, 1996, RUS' portfolio included about $32.3 billion in electricity-related loans and guarantees.[14] Most of the dollar amount of the portfolio is made up of loans to the G&T cooperatives. The principal outstanding on these G&T loans is approximately $22.5 billion, which is about 70 percent of the RUS electric loan portfolio. Distribution borrowers make up the remaining 30 percent of the electricity portfolio.

[14]Collectively, RUS has a portfolio of $42.5 billion in outstanding principal for utility loans including electricity, telecommunications, and water and waste disposal.

For a further discussion of RUS' financing and debt, see our report entitled, Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio (GAO/RCED-97-82, April 11, 1997) and appendixes V and VI of this report.

Power Marketing Administrations

The federal government owns and operates numerous multipurpose dams, many of which generate electric power. The power generated at these facilities is marketed through five federal entities called power marketing administrations (PMAS). The PMAS' mission is to market power generated at federal hydroelectric dams at the lowest possible rates to consumers, consistent with sound business principles. By law, PMAS are required to give priority in the sale of federal power to public power entities, such as public utility districts, municipalities, and customer-owned cooperatives. These customers are referred to as "preference customers."

The five PMAS—Southeastern Power Administration (Southeastern), Southwestern Power Administration (Southwestern), Western Area Power Administration (Western), Alaska Power Administration, and Bonneville Power Administration (BPA)—are part of the Department of Energy (DOE). Since the Alaska Power Administration is being sold to nonfederal entities, it is excluded from our analysis in this report. Additionally, throughout this report, we frequently discuss BPA separately from the other three PMAS because its revenue is more than twice as large as the other three PMAS combined and because it faces different operating risks.

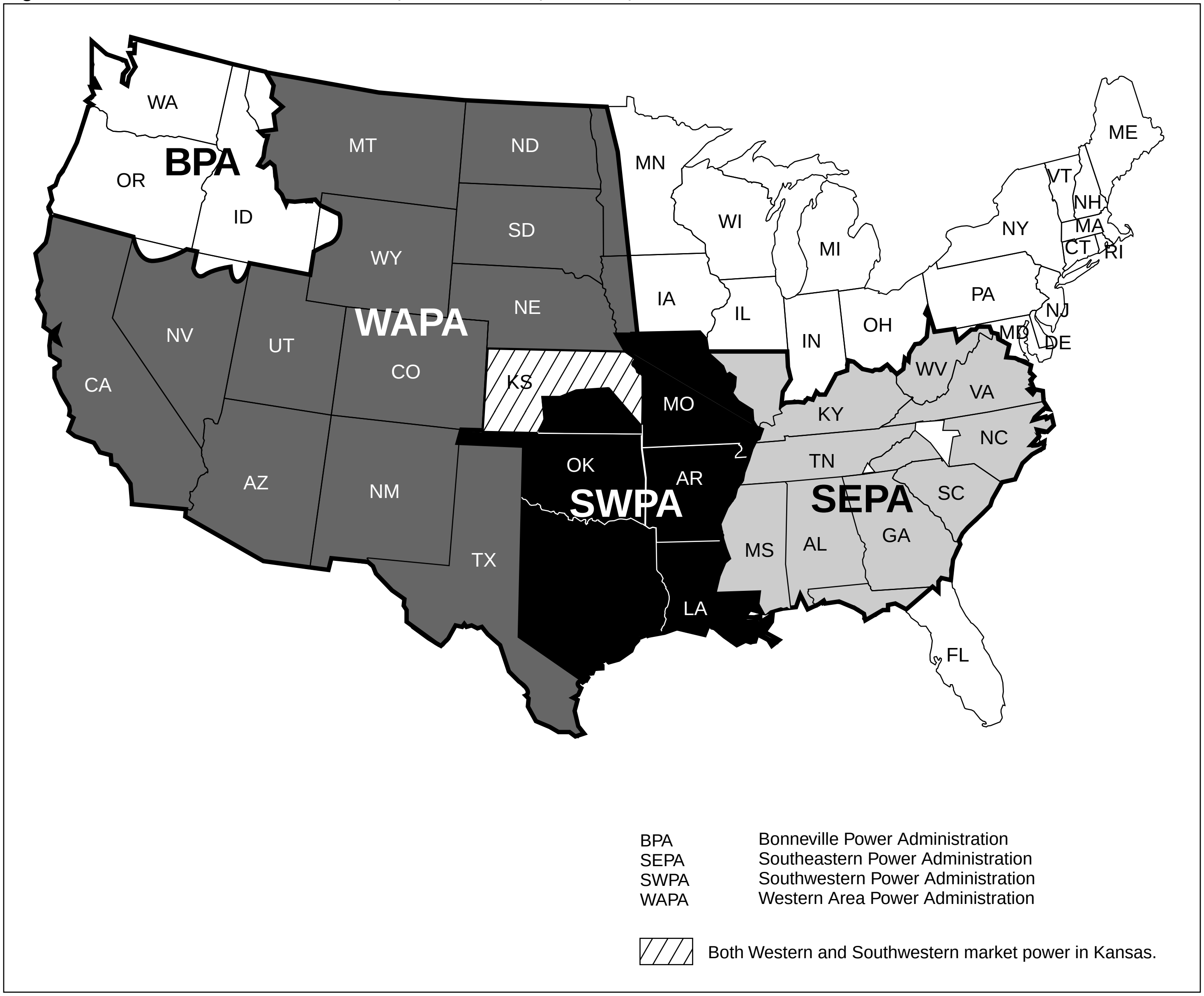
PMAS generally control and operate power transmission facilities[15] but do not control or operate the facilities (dams) that actually generate electric power. These power generating facilities were built and are operated by other federal agencies—most often by the Department of the Interior's Bureau of Reclamation (Bureau) or the U.S. Army Corps of Engineers (Corps). These agencies are referred to as the operating agencies. The operating agencies constructed these facilities as part of a larger effort in developing multipurpose water projects that have functions other than power generation, including flood control, irrigation, navigation, and recreation. The projects must be operated in a way that balances their authorized purposes—and, in many instances, power is not the primary use. Responsibility for operating the facilities to serve all of these multiple functions rests with the operating agencies.

[15]Southeastern has no transmission facilities.

PMAs sell electric power within 34 states—to all states except those in the Northeast and upper Midwest (see figure I.2).[16] Each PMA has its own specific geographic boundaries and system of projects from which power is marketed.

[16]In addition to the areas shown on the map, the Alaska Power Administration markets power in Alaska.

Figure I.2: Service Areas for Southeastern, Southwestern, Western, and BPA



Source: GAO analysis of data provided by the PMAs.

Role of Southeastern, Southwestern, and Western

Collectively, Southeastern, Southwestern, and Western sell power produced at 102 facilities and market it in 30 states (see figure I.2). In fiscal year 1995, they had total power revenue of almost $1 billion. The three PMAs differ substantially in size and revenue. Western is the largest, accounting for more than 4 times the revenue of either Southeastern or Southwestern. Southwestern and Western have their own transmission facilities, while Southeastern relies entirely on the transmission services of other utilities. Additional specific information about the three PMAs is shown in table I.1.

Table I.1: Information on the Three PMAs

	Year created	Number of hydroelectric plants Sept. 1995	Number of customers Sept. 1995	kWh sold (billions) fiscal year 1995	Revenue (in millions) fiscal year 1995	Miles of transmission lines
Southeastern	1950	23	296	6.8	$159	none
Southwestern	1943	24	95	7.7	114	1,380
Western	1977[a]	55	546	32.8	713	16,760
Total		**102**	**937**	**47.3**	**$986**	**18,140**

[a]In 1977, the DOE Organization Act established the Western Area Power Administration and transferred power marketing responsibilities and transmission assets previously managed by the Bureau of Reclamation to Western. The act also transferred the other PMAs from the Department of the Interior to DOE.

Power-Related Costs Must Be Recovered Through Rates

The Reclamation Project Act of 1939 and the Flood Control Act of 1944 generally require the recovery through power rates of costs of producing and marketing federal hydropower. However, these acts do not specify which costs are to be recovered, and as demonstrated in our previous report,[17] the three PMAs do not recover all power-related costs. The PMAs are required to recover the amount of their own appropriations as well as the power-related expenditures incurred by the operating agencies.

The three PMAs are generally funded through the annual appropriations process.[18] The three PMAs receive annual appropriations to make both capital expenditures, such as for PMA-controlled transmission facilities, as well as operations and maintenance (O&M) expenditures. PMAs generally pay for these expenditures by requesting Treasury to cut checks on their respective appropriations accounts. Unlike most other federal agencies, PMAs are required by law to recover through their rates, and repay to the Treasury, the amount appropriated for their power-related costs. The payments received from PMA customers are deposited directly to the

[17]Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, September 19, 1996).

[18]Some projects have been legislatively authorized to use revolving funds to finance some types of expenditures. In addition, some projects use nonfederal debt as a supplemental funding source.

general fund at Treasury via a lockbox. Ideally, over the course of a year, collections received by Treasury will offset, or "repay," amounts appropriated to the PMAs for O&M expenses, as well as an amortized amount of capital construction costs. The PMAs monitor expenses and revenues to ensure that power rates are sufficient to generate revenue to recover expenses.

The PMAs are required to recover not only their own costs, but also the power-related expenditures incurred by the operating agencies. The power-related portion of the operating agencies' expenditures includes all capital costs and O&M expenses that are solely related to the generation of power. In addition, a portion of the operating agency's "joint costs" is allocated to the PMAs. These joint costs are capital costs and O&M expenses related to both power production and some of the water project's other purposes. The operating agencies allocate the amount of joint costs that are power-related by applying a percentage established for each multiple-purpose project. PMAs set their rates to recover these costs from power revenues. The total revenues of any project administered by a PMA are to be sufficient to recover O&M expenses in the year incurred and to recover the federal investment (appropriations) in generation and transmission facilities (which we refer to as appropriated debt[19]), with interest, over a specified repayment period—generally 50 years for assets used to generate power and 35 to 45 years for assets used to transmit power.

PMAs' Debt

As shown in figure I.3, the three PMAs are collectively responsible for repaying about $7.2 billion of debt: $5.4 billion of appropriated debt,[20] $1.6 billion of irrigation debt, and about $0.2 billion in nonfederal debt.[21] Under reclamation law, Western is responsible for paying the costs of certain irrigation projects that are judged to be beyond the ability of the

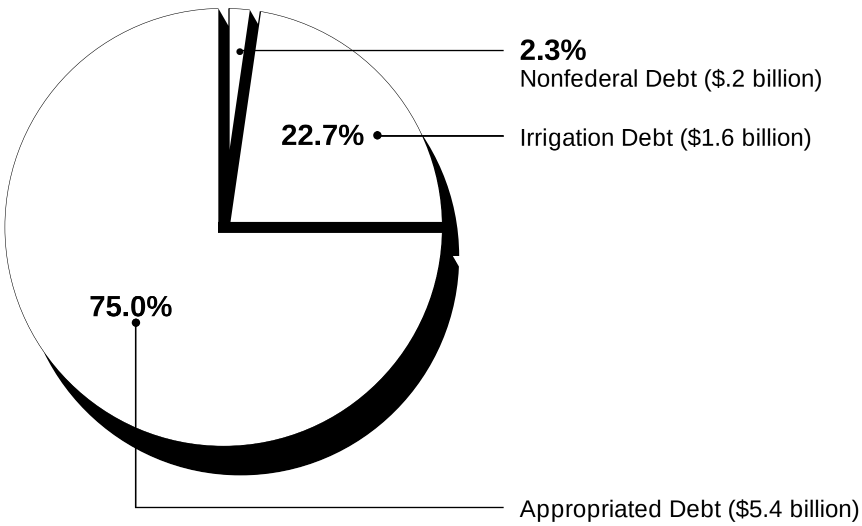
[19]We call this appropriated debt because PMAs are required to repay appropriations used for capital investments with interest. However, these reimbursable appropriations are not technically considered lending by Treasury.

[20]One and one half billion dollars of the appropriated debt was associated with Southeastern, $3.2 billion with Western, and $686 million with Southwestern. Audited figures for 1996 were unavailable at the time of our fieldwork for Southeastern and Southwestern, so September 30, 1995, balances are shown. According to the PMAs, these balances did not change significantly between 1995 and 1996.

[21]All irrigation debt and nonfederal debt is attributable to Western.

irrigators to repay.[22] We refer to these payments as irrigation debt. The nonfederal debt refers to capital provided by Western's customers (primarily through the issuance of bonds) to finance capital improvement projects.

Figure I.3: Composition of PMA Debt



Source: GAO analysis of data provided by the PMAs.

For a further discussion of the three PMAs' financing and debt, see our report, Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, September 19, 1996), and appendix VII of this report.

Role of Bonneville Power Administration

BPA was created in 1937 to market electric power from the Bonneville Dam and to construct facilities to transmit the power. It markets electric power

[22]Project authorizing legislation determines how the costs of constructing reclamation projects are allocated and how repayment responsibilities are assigned among the projects' beneficiaries. Collectively, the federal reclamation statutes that are generally applicable to all projects and the statutes authorizing individual projects are referred to as reclamation law. In implementing reclamation law, the Bureau of Reclamation and Western are guided by implementing regulations, administrative decisions of the Secretary of the Interior and the Secretary of Energy, respectively, and applicable court cases.

from the Federal Columbia River Power System, which consists of 29 federally-owned hydroelectric projects located primarily in the Columbia River Basin. BPA's primary customer service area, as shown in figure I.2, is a 300,000 square mile area of the Pacific Northwest, comprised of Oregon, Washington, Idaho, western Montana, and small portions of California, Nevada, Utah, and Wyoming. BPA sells primarily wholesale power from the dams and other generating plants to public and private utilities and direct service industries. By law, BPA gives preference to public utilities in sales of power and sells only excess power outside the Pacific Northwest. BPA builds, owns, and operates transmission lines that comprise 75 percent of the Northwest's high-voltage transmission capacity. (See table I.2.)

Table I.2: Information on BPA

	Year created	Number of hydroelectric plants Sept. 1995	Number of customers Sept. 1995	kWh sold (billions) fiscal year 1995	Revenue (in millions) fiscal year 1995	Miles of transmission lines
BPA	1937	29[a]	193	80.4	$2,182	15,012

[a]BPA has entered into nonfederal debt agreements to acquire all or part of the generating capacity of power projects of other entities, including four nuclear plants and some small hydroelectric projects.

The Federal Columbia River Power System provides roughly half the power used in the Pacific Northwest. BPA, the Corps, and the Bureau coordinate system operation with the many public and privately owned utilities that own dams on the river system. Over the years, Congress has expanded BPA's mission to include conservation and renewable resource development, rate relief for specified residential and small farm power users, and specific mandates for fish and wildlife protection and funding.

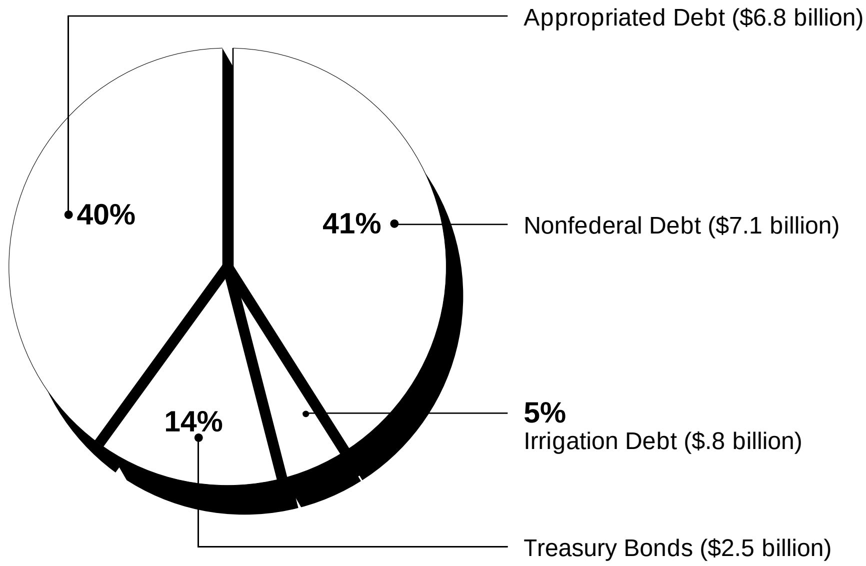
BPA's Power Program Is to Be Self-Supporting

Unlike the other PMAS, BPA no longer receives an annual appropriation. The Federal Columbia River Transmission System Act of 1974 placed BPA on a self-financing basis—so that its operating expenses are paid for by operating revenues (power and transmission sales). Funds received from customers are paid to BPA, which then deposits the receipts into a special BPA fund at Treasury. Expenditures for BPA are then paid for out of that special BPA fund at Treasury. To provide for capital expenditures, BPA does have authority to borrow from the Treasury. Treasury bond borrowing authority is capped at $3.75 billion ($2.5 billion for transmission and other capital investments and $1.25 billion for conservation and renewable energy investments). The agency is required to set its rates for power and transmission sales at levels that generate revenues sufficient to cover annual expenses and pay back previously appropriated funds. BPA is required to make an annual payment to Treasury that includes debt servicing costs on appropriated debt and Treasury bonds. Similar to the three PMAs discussed previously, BPA is also required to recover and repay to the Treasury the operating agencies' power-related capital and operating expenses. Unlike the other PMAs, BPA has a legislative mandate that requires it, within certain limits, to provide sufficient firm power to meet the needs of its primary regional customers.

BPA's Debt

As shown in figure I.4, BPA's total debt as of September 30, 1996, was $17.2 billion, including $6.8 billion for appropriated debt, $2.5 billion for Treasury bonds, $7.1 billion for nonfederal debt, and $0.8 billion in irrigation debt.

Figure I.4: Composition of BPA's Total Debt as of September 30, 1996



Source: GAO analysis of data provided by BPA.

In the late 1960s, BPA and the region's utilities forecasted that electrical demand would triple between 1970 and 1990 and concluded that the region needed to supplement its hydroelectric capacity with new forms of generation. Subsequently, BPA entered into nonfederal financing agreements to acquire all or part of the output of four nuclear power plants constructed, owned, and to be operated by other entities. As part of these agreements, BPA was required to pay for the annual project costs, including debt service, in amounts ranging from 30 to 100 percent of total costs incurred. Later, a variety of events, including construction cost overruns and overly optimistic estimates of electricity demand, made it clear that some of these plants would not be economical to complete or operate. Accordingly, construction was halted on two of these nuclear plants and they were not completed. In addition, one previously operating plant has been shut down permanently. As a result, BPA is responsible for approximately $4.2 billion in nonfederal debt associated with three nonoperating nuclear plants and an additional $2.5 billion in nonfederal debt associated with the one operating nuclear plant.[23]

For a further discussion of BPA's financing and debt, see our report, Bonneville Power Administration: Borrowing Practices and Financial Condition (GAO/AIMD-94-67BR, April 19, 1994), and appendix VIII of this report.

The Tennessee Valley Authority

The Tennessee Valley Authority (TVA) is a multipurpose, independent federal corporation established by the Tennessee Valley Authority Act of 1933.[24] The act established TVA to improve the quality of life in the Tennessee River Valley by improving navigation, promoting regional agricultural and economic development, and controlling the flood waters of the Tennessee River. To those ends, TVA erected dams and hydroelectric power facilities on the Tennessee River and its tributaries. To meet the need for more electric power during World War II, TVA expanded beyond hydropower, building coal-fired power plants. In the 1960s, TVA decided to add nuclear generating units to its power system to meet projected heavy growth in electricity demands.[25]

Today, TVA's other roles have been eclipsed by its electricity program. TVA has become the nation's largest electric power generator, with a dependable capacity in service of over 28,000 megawatts and 16,021

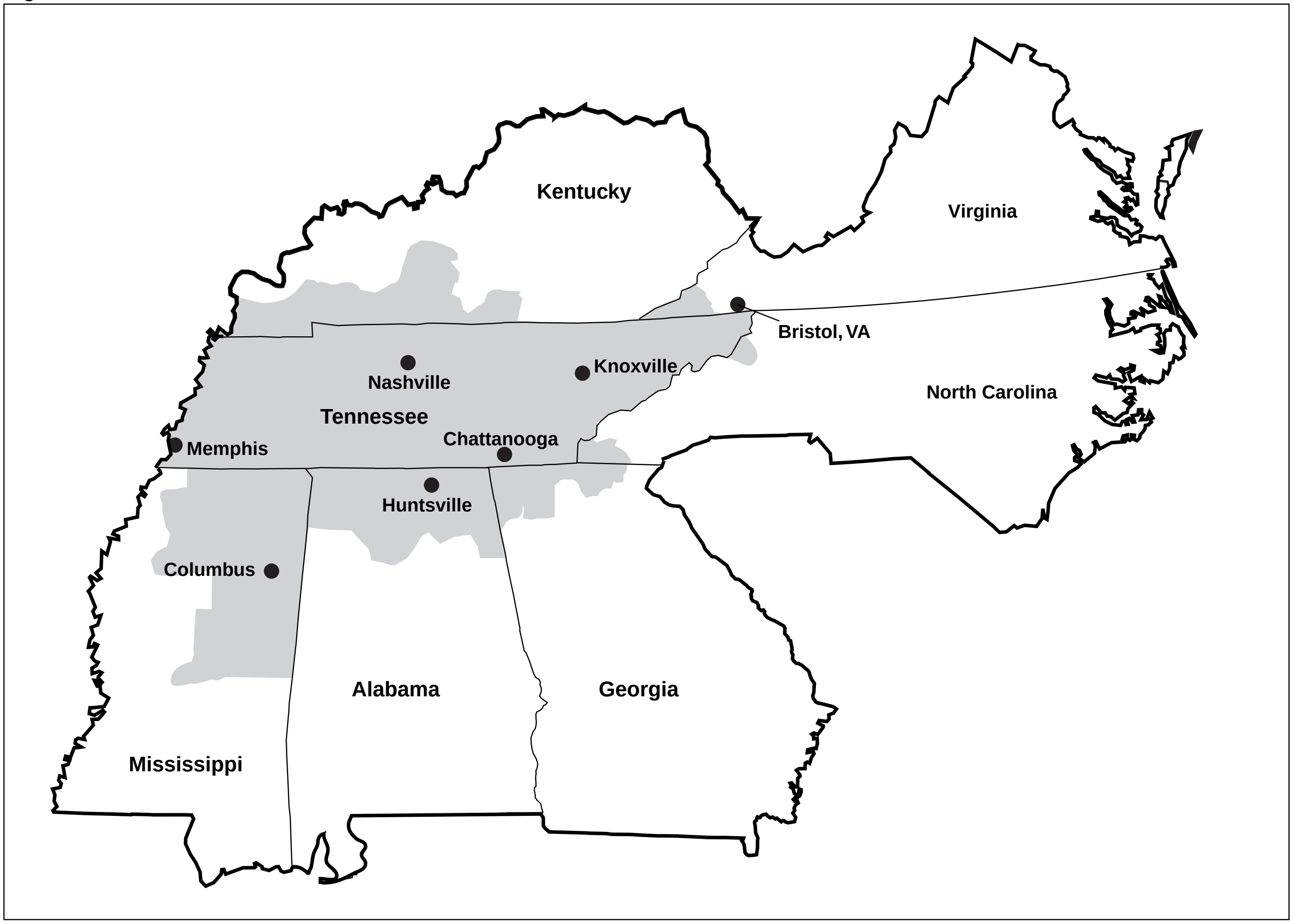
[23]The nonfederal debt also consists of $321 million invested in small hydroelectric projects and conservation measures.

[24]The TVA Act as amended (16 U.S.C. 831 et seq.) provides the basic statutory authority for TVA.

[25]For a more detailed discussion of TVA's nuclear program, see Tennessee Valley Authority: Financial Problems Raise Questions About Long-term Viability (GAO/AIMD/RCED-95-134, August 17, 1995).

employees as of September 30, 1996. TVA sells power in seven states—Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee, and Virginia—as illustrated in figure I.5. Additional specific information about TVA is shown in table I.3.

Figure I.5: TVA Service Area



Source: Developed by GAO from data provided by TVA.

Table I.3: Information on TVA

	Year created	Number of hydroelectric plants Sept. 1996	Number of customers Sept. 1996	kWh sold (billions) fiscal year 1996	Revenue (in millions) fiscal year 1996	Miles of transmission lines
TVA	1933	29[a]	160[b]	140.6	$5,693[c]	17,000

[a]These 29 plants have 109 generating units. TVA also has 4 additional units at a pumped storage plant, 59 units at 11 coal-fired plants, 48 combustion turbines at 4 sites, and 5 operating nuclear units at 3 plants.

[b]TVA sells primarily wholesale power. As of September 30, 1996, TVA's 160 wholesale distributors—municipal and cooperatives—in turn sell power on a retail basis to nearly 8 million customers. TVA also has about 67 directly served large industrial customers and federal agencies.

[c]Total operating revenues from power programs.

Legislation Affecting TVA

TVA's authorizing legislation allows it to operate with a relatively high degree of independence. The TVA Act of 1933 did not subject TVA to the regulatory and oversight requirements that must be satisfied by commercial electric utilities. As opposed to the regulatory environment faced by other utilities, all authority to run and operate TVA is vested in TVA's three-member board of directors, including the sole authority to set wholesale electric power rates and approve the retail rates charged by TVA's distributors.[26] The three board members are full-time employees of TVA. They are appointed by the President, with the advice and consent of the Senate, and serve 9-year overlapping terms of office. The President designates one member as the chairman.

In 1959, the Congress amended the TVA Act in an attempt to protect surrounding utilities from competition with TVA because it was a low-cost federal utility. By establishing what is commonly referred to as the TVA "fence," the 1959 amendments prohibited TVA—with some exceptions—from entering into contracts to sell power outside the service area TVA and its distributors were serving on July 1, 1957. TVA was allowed to continue to sell power to certain other utilities outside of its service area if the power is surplus to the requirements of TVA's own customers. TVA can also buy power when needed.

[26]TVA is subject to some other regulatory actions, such as the Nuclear Regulatory Commission's (NRC) role in licensing and inspecting nuclear facilities and the Environmental Protection Agency's environmental regulations.

Because TVA is, for the most part, legally prohibited from making sales outside of its service area, the Energy Policy Act of 1992 exempted TVA from its wheeling requirements.[27] This exemption prevents competitors from using TVA's transmission system to sell to customers inside TVA's service area.[28] TVA is therefore generally insulated from wholesale competition and remains in a position similar to a regulated utility monopoly.

TVA's Power Programs Are to Be Self-Supporting

As mentioned, TVA's programs are divided into two types of activities—the nonpower programs and the power programs. The nonpower programs, such as water resources, navigation, and flood control, are primarily funded through federal appropriations and user fees. These programs received about $109 million in funding in fiscal year 1996 and are operated primarily within the 41,000 square mile Tennessee River watershed.[29] Since the 1959 amendments to the TVA Act, TVA's power program does not receive any federal appropriations and is required to be self-supporting, so that their operating expenses are paid for by operating revenues (power sales). TVA's power program generated about $5.7 billion in fiscal year 1996 revenues, with about $5.0 billion (88 percent) of this amount coming from the 160 wholesale distributors. The other 12 percent primarily came from sales to directly served industries and federal agencies.

TVA's Debt

Although TVA's power programs are required to be self-funded, TVA is authorized to use debt financing to pay for capital improvements in excess of internally generated funds. In 1959, TVA was authorized to borrow by issuing bonds and notes with a debt limit set by the Congress at $750 million. Since then, TVA's debt limit has been increased four times by the Congress and is currently capped at $30 billion. As of September 30, 1996, TVA had accumulated almost $28 billion in debt: $3.2 billion in direct federal borrowing from FFB and $24.1 billion in publicly issued TVA debt (which is not explicitly guaranteed by the federal government). In addition, TVA is also required to repay funds appropriated to it prior to becoming self-funding in 1959—the outstanding balance was approximately $600 million as of September 30, 1996. Although we refer to

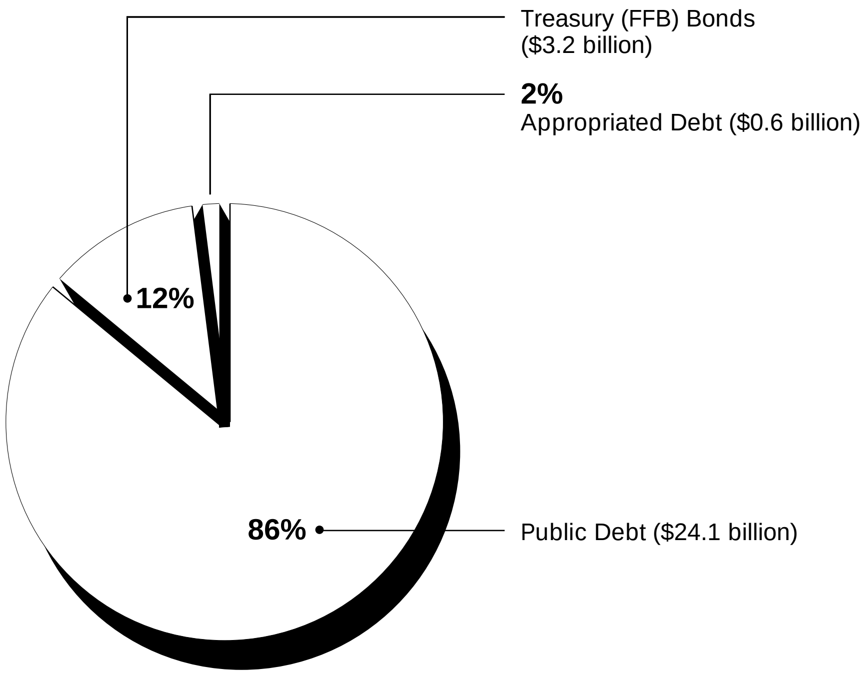
[27]Section 722 of the Energy Policy Act of 1992, 106 Stat 2919.

[28]However, the exemption specifically did not cover the Bristol Virginia Utilities Board.

[29]TVA's nonpower programs were not included in the scope of this report.

this as appropriated debt, this amount does not count toward TVA's $30 billion debt cap.[30]

Figure I.6: Composition of TVA Debt as of September 30, 1996



Source: GAO analysis of data provided by TVA.

For a more detailed discussion of TVA's financing and debt, see our report, Tennessee Valley Authority: Financial Problems Raise Questions About Long-term Viability (GAO/AIMD/RCED-95-134, August 17, 1995), and appendix IX of this report.

[30]TVA refers to this as "appropriation investment" and treats it as a proprietary capital account for financial statement purposes.

Objectives, Scope, and Methodology

The Chairman, House Committee on the Budget, and the Chairman, Subcommittee on Water and Power Resources, House Committee on Resources, asked us to review several issues relating to federal electricity finances. The specific objectives of our review were to (1) estimate the federal government's fiscal year 1996 net recurring cost and, where possible, fiscal years 1992 through 1996 cumulative net recurring cost[1] from ongoing operations of electricity-related activities at the Rural Utilities Service (RUS), the Department of Energy's (DOE) power marketing administrations[2] (PMAS), and the Tennessee Valley Authority (TVA) (see appendixes IV and V) and (2) assess the likelihood of future losses beyond the net recurring costs to the federal government from the electricity-related activities of these entities (see appendixes VI, VII, VIII, and IX).

As agreed with the requesters, we did not (1) estimate the forgone revenue for federal, state, or local governments resulting from the tax exempt status of the RUS borrowers, the PMAs, or TVA, (2) estimate the forgone revenue for federal and state governments resulting from tax-exempt debt instruments issued by TVA or related to Western or BPA nonfederal debt, (3) assess the reasonableness of the methodologies used by the operating agencies to allocate power-related costs to the PMAs for recovery, or (4) quantify the amount of potential future losses to the federal government.

As also agreed with the requesters, we did not include the following in our review: the Alaska Power Administration, the Federal Energy Regulatory Commission (FERC), the nonpower aspects of RUS and TVA, and the Nuclear Regulatory Commission (NRC). As agreed, we estimated the net cost to the federal government on the accrual basis of accounting.[3] These net costs either already have had or will have an impact on the federal budget. In addition, it was beyond the scope of our review to evaluate the public benefits provided by the PMAS, RUS, and TVA to their respective regions.

[1]Estimates of cumulative net costs for fiscal years 1992 through 1996 are stated in constant 1996 dollars.

[2]We reviewed the electricity related activities of four PMAs: Bonneville Power Administration (BPA), Southeastern Power Administration (Southeastern), Southwestern Power Administration (Southwestern), and Western Area Power Administration (Western). Because BPA faces different operating risks and its annual revenue is more than 2 times larger than the other three PMAs combined, we frequently discuss BPA separately. Since legislation has been enacted to sell the Alaska Power Administration to nonfederal entities, it was excluded from our review.

[3]The accrual basis of accounting recognizes the impact of revenue and expense transactions on the financial statements in the time period when they occur.

The following sections detail the methodologies used in our analyses and additional restrictions on the scope of our work.

Federal Government's Direct and Indirect Financial Involvement in the Electricity-Related Activities at RUS, the PMAs, and TVA

Net recurring costs and exposure to additional financial losses result from the federal government's direct and indirect financial involvement in the electricity-related activities of these entities. For this report, we defined direct involvement in electricity activities as loans or loan guarantees made by the federal government directly to RUS borrowers and appropriated debt[4] owed by the PMAs or TVA. As of September 30, 1996, the federal government had over $53 billion of direct financial involvement. The federal government would have financial losses from its direct involvement if the RUS borrowers or the federal entity were unable to repay debt owed to the federal government.

For this report, we defined indirect involvement as nonfederal financing. As of September 30, 1996, the federal government had indirect financial involvement of over $31 billion—primarily nonfederal financing of BPA[5] and bonds issued by TVA. Although BPA's nonfederal financing and TVA bonds are not explicitly guaranteed by the federal government, the financial community generally views them as having an implicit federal guarantee. The federal government would have losses from its indirect involvement if it incurred unreimbursed costs as a result of actions it took to prevent default on nonfederal debt service payments or breach of contract by the federal entity on nonfederal financing.

[4]We call this appropriated debt because the PMAs are required to recover from ratepayers, with interest, appropriations used for capital investments, including funds appropriated to construct, as well as to operate and maintain, power-related facilities. However, these amounts are not technically considered lending by Treasury.

[5]BPA calls this "nonfederal project financing." BPA used its contracting authority to acquire all or part of the generating capability of power projects or other entities. Under these agreements, BPA contracts to pay all or part of the annual project budgets, including debt service, whether or not the projects are completed. BPA does not have the authority to borrow from nonfederal sources. See appendix VIII for additional discussion. For Western, nonfederal financing refers to capital provided by its customers (primarily through the issuance of bonds) to finance capital improvement projects.

Assessing the Net Cost From Ongoing Operations of Electricity-Related Activities at RUS, the PMAs, and TVA

In order to assess the federal government's net recurring cost from ongoing operations of electricity-related activities, we defined the full cost of the PMAS and TVA producing and marketing federal power and of RUS providing loans and loan guarantees to its borrowers based on our review of applicable federal guidance and industry practice. Then, we determined whether, for each entity, (1) there is a net financing cost, (2) pension and postretirement health benefits were fully recovered, and (3) other costs were fully recovered.

Most of the data used in our analysis was obtained from audited financial statements. Independent public accounting firms or Offices of Inspector General audited the financial statements of RUS, the PMAS, and TVA in accordance with private sector and government auditing standards. On the basis of their audits, the firms or Offices of Inspector General issued opinions on the fairness of the agency's financial statements and the adequacy of the agency's internal controls and compliance with laws and regulations.

The 1996 financial operations of RUS were audited by the Department of Agriculture's (USDA) Office of Inspector General. RUS is a component of USDA's rural development mission area and is included as part of the rural development's consolidated financial statements. USDA's Office of Inspector General issued a qualified opinion on the 1996 financial statements for the rural development mission area because of weaknesses in the estimation and reestimation of loan subsidy costs related to the Federal Credit Reform Act of 1990.[6] However, the qualification did not affect the data that we needed to conduct our analysis of net financing costs. RUS' fiscal years 1992 through 1995 financial statements were audited by Urbach Kahn & Werlin (UKW). UKW issued an unqualified opinion on RUS' financial statements for 1992 through 1995, indicating that the financial statements were fairly stated in all material respects.

BPA's financial statements are audited by Price Waterhouse. Price Waterhouse issued an unqualified opinion on BPA's financial statements for

[6]RUS is required to budget for and report on its loans and guarantees in accordance with the requirements of the Federal Credit Reform Act of 1990 and Statement of Federal Financial Accounting Standards (SFFAS) No. 2, Accounting for Direct Loans and Loan Guarantees. The two key principles of credit reform contained in the Federal Credit Reform Act center on the (1) definition of cost in terms of the present value of the estimated net cash flow over the life of a credit instrument and (2) inclusion in the budget of the estimated costs of credit programs before direct or guaranteed loans are made or modified. The budget and accounting requirements under credit reform were effective for loans and guarantees made after October 1, 1991. The majority of RUS electricity loans and guarantees were made prior to October 1, 1991 and therefore are not reported under credit reform requirements. Additionally, because the credit reform estimates are not reliable at RUS, we chose to use actual costs incurred rather than any credit reform cost estimates for our analysis.

fiscal years 1992 through 1996, indicating that the financial statements were fairly stated in all material respects. Western's fiscal years 1992 through 1996 financial statements and Southeastern's and Southwestern's fiscal years 1994 and 1995 financial statements were audited by KPMG Peat Marwick (KPMG). KPMG was hired by the DOE Inspector General to perform the audits of these PMAS. KPMG issued an unqualified opinion on Western's fiscal years 1992 through 1996 financial statements and on Southeastern's and Southwestern's fiscal years 1994 and 1995 financial statements. Audited financial statements for 1996 were not available for Southeastern and Southwestern; therefore, we used 1995 audited financial statements. Southeastern's fiscal years 1992 and 1993 financial statements were audited by Deloitte & Touche, which issued an unqualified opinion on them. Southwestern's fiscal years 1992 and 1993 financial statements were audited by RJ Miranda & Company and Price Waterhouse, which issued unqualified opinions on them.

The financial statements of TVA are audited by Coopers & Lybrand, which issued an unqualified opinion on TVA's fiscal years 1992 through 1996 financial statements, indicating that the financial statements were fairly stated in all material respects. However, in 1994 and 1995, the opinions also included a "matter of emphasis" relating to TVA's deferred nuclear assets.

While it was not within the scope of our work to assess the overall quality of the auditors' work, we reviewed selected 1996 audit work papers (1995 audit work papers for Southeastern, Southwestern, and Western) and management letters to obtain background information. Throughout our report, where possible, we used audited numbers from each entity's 1996 and prior years' annual reports. In addition, where possible, we used audited numbers from the 1996 and prior years' annual reports of IOUS and RUS generation & transmission cooperatives.

We interviewed numerous officials at RUS, the PMAS, the operating agencies, and TVA. We provided questions to each of the respective entities relating to cost recovery and other matters addressed in our report. We analyzed data provided to us by the entities to determine which costs are and are not fully recovered from borrowers or ratepayers. The net costs identified in this report focus on the material items we found in reviewing the data sources described in this appendix. There could be additional net costs that did not come to our attention during this review.

Defining the Full Cost of Producing and Marketing Federal Power and of Providing Loans and Loan Guarantees to Borrowers

To define the full costs associated with producing and marketing federal power and of providing loans and loan guarantees to borrowers, we referred to Office of Management and Budget (OMB) Circular A-25, User Fees, which provides guidance for use in setting fees to recover the full costs of providing goods and services. The circular defines full cost as all direct and indirect costs of providing goods and services and is consistent with guidance of full cost reporting contained in Statement of Federal Financial Accounting Standards (SFFAS) No. 4, Managerial Cost Accounting Concepts and Standards for the Federal Government and industry practice. In accordance with the criteria from OMB Circular A-25, SFFAS No. 4, and industry practice, the full cost of producing and marketing power or providing loans and loan guarantees is the sum of all direct and indirect costs incurred by RUS, the PMAs, and TVA and the costs incurred by any other agencies to support the operations of RUS, the PMAs, and TVA.

Assessing Net Financing Costs

For this report, we defined the net financing cost to the Treasury as the difference between Treasury's borrowing cost or interest expense and the interest income received from RUS borrowers, the PMAs, and TVA. Our objective was to determine what the net cash flow was to the federal government from lending transactions with its electricity-related activities.[7] Treasury's borrowing cost is particularly relevant because the federal government has had debt outstanding since before 1940—before the oldest RUS borrowers and PMA or TVA debt still outstanding—and has had a deficit every year since 1969. Thus, it is reasonable to assume that the federal government has had to issue debt to extend financing to RUS borrowers, the PMAs, and TVA.

Our basic methodology was to determine whether the federal government received a return sufficient to cover its borrowing costs and, if not, to estimate the net financing cost. RUS, the PMAs, and TVA had several forms of federal debt outstanding at September 30, 1996. Each of these forms of federal debt had different terms and thus required us to apply different variations of our basic methodology in assessing whether there was a net financing cost to the federal government and, if so, measuring the magnitude of this net cost. The following are the specific methodologies

[7]If our objective had been to calculate an economic financing subsidy rather than the net cash flow to Treasury, consideration of other forms of subsidy would have been necessary. For example, our calculation of net financing cost excludes the impact that the risk of federal hydropower projects might have had on the PMAs' interest rates if they had been financed in the private market rather than through Treasury. Our methodology also does not consider the difference between Treasury debt being compounded semiannually versus PMA and RUS debt being compounded annually.

used for RUS financing and PMA appropriated debt, TVA's appropriated debt, TVA's Federal Financing Bank (FFB) debt, and BPA's Treasury bonds.

RUS Financing and PMA Appropriated Debt

We assessed the net financing cost of the RUS loan portfolio and PMA appropriated debt using substantially the same methodology, which we refer to as the portfolio methodology. Under this methodology, we obtained the amount of interest income paid to the federal government by RUS borrowers and the PMAs from the audited 1996 financial statements.[8] Since Treasury does not match its borrowing with loans made to RUS borrowers or the PMAs' appropriated debt financing and does not specifically price the debt based on its terms, the federal government's interest expense associated with the funds provided to the RUS borrowers and PMAs must be estimated. PMA appropriated debt and RUS borrower loans have fixed interest rates over terms of up to 35 years for RUS borrowers and 50 years for PMAs. Treasury does not have the ability to call[9] PMA appropriated debt or RUS borrower loans.

To estimate the federal government's interest expense, we used the weighted average interest rate on Treasury's entire outstanding bond portfolio because it best reflects its cost of long-term borrowing. The bond portfolio's average interest rate includes bonds with varying maturities up to 30 years. Treasury's bond portfolio average interest rate of 9 percent was obtained from the Monthly Statement of the Public Debt of the United States as of September 30, 1996. This document is published by the Bureau of Public Debt, Department of Treasury. Specific calculations of interest expense using the 9 percent Treasury cost of funds are discussed below.

Although both PMA appropriated debt and RUS borrower loans are long term with fixed interest rates, application of the portfolio methodology varies to some extent, as described below.

RUS Financing

There are four main aspects of the net financing cost to Treasury of the RUS debt, although not all RUS debt has each of these elements. The first is the difference between the RUS borrower's interest rate and the interest rate on the closest match of Treasury borrowing in terms of maturity at the time the loan was made (interest rate spread). The second is that

[8]Because audited fiscal year 1996 data were not available for Southeastern and Southwestern at the time of our fieldwork, we used fiscal year 1995 appropriated debt and weighted average interest rates. According to the PMAs, these balances did not significantly change from 1995 to 1996. We then estimated fiscal year 1996 net financing cost using the 1996 Treasury average interest rate.

[9]Call refers to the ability of the lender to require the borrower to pay back the debt before its maturity date.

financially troubled RUS borrowers have missed significant scheduled loan payments (delinquent interest payments). The third is that RUS borrower loans have maturities of up to 35 years, which is beyond the maximum maturity of Treasury bonds. Thus, if RUS borrowers do not repay their loans within 30 years, Treasury would have to refinance its corresponding debt (maturity differential). The fourth is that Treasury's borrowing practices are inflexible in that it is generally unable to refinance or prepay outstanding debt in times of falling interest rates (Treasury borrowing practices).

In order to calculate the net financing costs to Treasury under the portfolio method, we obtained the federal government's annual interest income from RUS borrowers from supporting financial statement documentation. RUS does not recognize interest income on delinquent loans, which reduces its interest income. Interest income on delinquent loans is recorded when it is received.

To calculate the federal government's annual interest expense, we added the estimated interest expense paid by Treasury to bondholders to finance RUS federal debt and the interest expense paid to private lenders. Interest from government borrowing was estimated by multiplying the amount of RUS federal government borrowing outstanding by the average interest rate Treasury was paying on its portfolio of bonds outstanding at the end of fiscal year 1996—9 percent. For interest expense to private lenders, we obtained the actual amounts paid to the lenders from supporting financial statement documentation and other supporting documents. The sum of interest expense on federal and private debt yields an estimate of the amount of annual interest expense Treasury must pay on the RUS loan portfolio. We obtained the total RUS debt owed to Treasury and FFB from the final trial ledger balance. Finally, we subtracted the interest income received by Treasury from RUS borrowers from the estimated interest expense paid by Treasury on the RUS loan portfolio. The difference between these two amounts constitutes the net financing costs to Treasury. See appendix V for a detailed calculation of the RUS net financing cost.

PMA Appropriated Debt

There are four main aspects of the net financing cost to the federal government from the PMAs' appropriated debt, although not all PMA debt has each of these elements. The first is the difference between the PMA borrowing rate and the interest rate on the closest match of Treasury borrowing in terms of maturity at the time of the appropriation (interest rate spread). The second is the PMAs' ability to repay the highest interest-bearing appropriated debt first (prepayment option). The third is that Treasury's borrowing practices are inflexible in that it is generally unable to refinance or prepay outstanding debt in times of falling interest rates (Treasury borrowing practices). This inflexibility is part of the reason for Treasury's relatively high cost of funds—9.0 percent on its outstanding portfolio of bonds as of September 30, 1996. The fourth is that PMA appropriated debt has maturities of up to 50 years, which is beyond the maximum maturity of Treasury bonds. Thus, if appropriated debt is not repaid within 30 years, Treasury would have to refinance its corresponding debt (maturity differential).

In order to calculate the net financing costs to the Treasury under the portfolio method, we obtained the federal government's annual interest income from the PMAs by multiplying the amount of PMA appropriated debt outstanding at September 30, 1996, by the weighted average interest rate paid by the PMAs. Appropriated debt and the weighted average interest rate paid by the PMAs were taken from the 1996 audited financial statements.[10] We reconciled these figures to interest expense and capitalized interest reported in the PMAs' audited financial statements.

To calculate interest expense for the federal government, we multiplied the amount of PMA appropriated debt outstanding by the average interest rate Treasury was paying on its portfolio of bonds outstanding at the end of fiscal year 1996—9 percent—which yields an estimate of the amount of interest expense Treasury must pay on the PMAs' outstanding appropriated debt. The difference between the federal government's interest income and interest expense represents the net financing cost. For a further discussion of PMA financing, see Power Marketing Administrations: Cost Recovery, Financing, and Comparisons to Nonfederal Utilities (GAO/AIMD-96-145, September 19, 1996).

To assess the effects of the restructuring of BPA's appropriated debt, we reviewed the provisions of the BPA Appropriations Refinancing Act and examined the mechanics of how the restructuring was to take place under the act. We also discussed the restructuring with BPA officials and reviewed BPA documents regarding the implementation of the act and its effects on BPA's appropriated debt and interest expense. We did not perform any calculations to determine the accuracy of the position taken by BPA that the present value of the appropriated debt after the restructuring is identical to the present value of this debt prior to the

[10]As previously discussed, we used 1995 data for Southeastern and Southwestern because their 1996 audited financial statements were not available.

restructuring. We also did not review the impact of the debt restructuring on the federal budget.

Loan-by-Loan Methodology

The net financing cost for RUS financing and PMA appropriated debt in our report is calculated using the portfolio methodology. We also calculated the net financing costs to the Treasury under an alternative methodology we refer to as the loan-by-loan methodology. This methodology attempts to match the RUS federal debt and the appropriated debt of two of the PMAS—Southwestern and BPA—with Treasury borrowing. The loan-by-loan methodology assumes that in order to provide up to 50-year financing for a PMA project and up to 35-year financing for RUS debt, the Treasury must borrow an equivalent amount via the sale of long-term bonds. Because Treasury does not borrow for more than 30-year terms, this methodology also assumes that when necessary, Treasury must refinance each borrowing to extend the financing to the PMAS or RUS borrowers for the remainder of the terms of the debt.

We performed this analysis to estimate the 1996 net financing cost for Southwestern, BPA, and RUS. We found that the loan-by-loan methodology resulted in a larger net financing cost for Southwestern and BPA, and the same for RUS. Thus, the portfolio methodology is generally a more conservative estimate of the magnitude of the net financing cost for this debt. However, the primary reason we did not use the loan-by-loan methodology to calculate net financing costs is that Treasury does not match its borrowing with RUS financing or PMA appropriated debt. Thus the loan-by-loan methodology is less realistic than the portfolio methodology in estimating what the actual net cost of PMA appropriated debt and RUS financing is to the federal government.

Other Financing for TVA and BPA

TVA had outstanding appropriated debt[11] and FFB debt and BPA had outstanding Treasury bonds at September 30, 1996. Unlike the PMA appropriated debt and RUS financing, these financing arrangements were designed so that Treasury would recover its cost of providing the funds to TVA and BPA. To determine whether TVA appropriated debt, TVA FFB debt, and BPA Treasury bonds resulted in a net financing cost to the federal government, we assessed whether the terms of each type of debt resulted

[11]We call this appropriated debt because TVA is required to repay all but $258.3 million of the appropriations that were used for capital investments, plus interest. However, these reimbursable appropriations are not technically considered lending by the Treasury. In addition, TVA refers to this debt as appropriation investment and considers it to be equity. Accordingly, TVA considers annual payments as a reduction of equity capital and the annual return as a dividend. We refer to the annual payments as principal payments, and the annual return as interest expense.

in recovery of a reasonable approximation of the federal government's cost of providing the funds.

TVA's Appropriated Debt

As of September 30, 1996, TVA had $608 million of appropriated debt outstanding that represented appropriations received by TVA to construct its hydroelectric dams, fossil plants, transmission system, and other general assets of the power program. This debt was incurred from the inception of TVA in 1933 through 1959. When the TVA Act was amended in 1959 to give TVA the authority to "self-finance," TVA was required to begin making annual payments from net power proceeds for principal on this debt, plus a market rate of return (interest expense) to Treasury on the unpaid balance. TVA's appropriated debt has substantially different terms than the PMAS' appropriated debt. First, annual principal payments (currently $20 million) are required for the more than 50 years from 1959 until TVA pays down the balance to $258.3 million. Once the balance is $258.3 million, TVA is required to continue to pay annual interest expense on this balance. Second, the interest rate on TVA's appropriated debt is variable and is reset each year. The interest rate used is the rate on Treasury's total marketable public obligations outstanding at the beginning of the year. Thus, unlike PMA appropriated debt, which has a fixed interest rate for up to 50 years, TVA's appropriated debt is similar to a variable interest rate loan. As a result, TVA's interest payments to Treasury have and should continue to approximate Treasury's total cost of funds over time.

Because the repayment terms of this debt include a 1-year variable interest rate, which is a short-term debt feature, and a repayment term of more than 50 years, which is characteristic of long-term debt, we concluded that use of Treasury's average interest rate for all marketable public obligations results in a reasonable return and no net cost to the federal government.

TVA's Federal Financing Bank Debt

As of September 30, 1996, TVA had $3.2 billion of long-term debt held by FFB. This debt was issued from 1985 to 1989, with maturities ranging from 14 to 30 years and fixed interest rates ranging from 8.5 percent to 11.7 percent. FFB cannot call this debt and TVA cannot prepay this debt unless it pays FFB the present value of the future cash flows using current

FFB interest rates.[12] This debt matures in fiscal years 2003 through 2016. For fiscal years 1992 through 1996, TVA had varying amounts of FFB debt outstanding.

FFB obtains its funds by borrowing from the Department of the Treasury. FFB has a stated policy to provide funds at Treasury's cost of money. Each loan made by FFB matches the terms and conditions, except for the interest rate, of the corresponding loans made by Treasury to FFB. FFB charges TVA the interest rate it incurs on the Treasury borrowing, plus a fee of one-eighth-of-one-percent to cover administrative costs.[13] Because the interest rate on TVA's FFB debt is based on the interest rate paid by the Treasury on similar term debt plus a one-eighth of one percent administrative fee, we concluded that Treasury is recovering its cost of funds and that there is no net financing cost to the federal government.

Recently, TVA asked FFB to allow it to repay this debt before its maturity dates. However, TVA was not willing to incur the prepayment premiums required under the terms of the existing loan contracts with FFB. In 1995, the Congressional Budget Office (CBO) was asked to review proposed legislation that would have authorized TVA to prepay $3.2 billion in loans made by FFB without paying the prepayment premiums. CBO estimated that enacting such legislation in 1996 would have increased federal outlays by about $120 million per year through 2002, with declining amounts thereafter until the last notes matured in the year 2016. We concur with CBO's assessment. This proposed legislation was never introduced.

BPA's Treasury Bonds

As of September 30, 1996, BPA had $2.5 billion of medium- and long-term debt held by Treasury in the form of BPA bonds. Interest rates on this debt are fixed and are set using rates comparable to the debt issued by U.S. government corporations with similar terms. Some of this debt is callable by BPA. The call premium BPA paid was also based on premiums for similar debt. The debt matures in fiscal years 1997 through 2034. For fiscal years 1992 through 1996, BPA had varying amounts of FFB debt outstanding.

[12]FFB charges the prepayment premium to protect itself from incurring an economic loss on the prepayment. This premium is calculated based on the difference between the book (face) value and the Treasury market value of the loan. The loan's market value is calculated based on the net present value of the future stream of principal and interest payments the government gives up when FFB accepts prepayment of a loan. We did not review the Congressional Budget Office's calculation of the increase in federal outlays that would result if TVA were allowed to repay its FFB debt without paying the prepayment premiums.

[13]TVA also has the option of repurchasing the FFB bonds under standard FFB prepayment provisions.

We discussed the mechanics of the borrowing process with cognizant BPA and Treasury representatives. In addition, we examined the process by which Treasury sets interest rates and call premiums. Because the BPA bonds result in a return to the Treasury that approximates its cost of funds, we believe that there is no net cost to the federal government.

Assessing the Recovery of Pension and Postretirement Benefits

To assess whether pension and postretirement health benefits were fully recovered by RUS, the PMAS, and TVA, we consulted with representatives from the Office of Personnel Management's Office of Actuaries. We determined that certain Civil Service Retirement System (CSRS) pension benefits were not being recovered by RUS, the PMAS, and TVA. We also determined that all postretirement health benefits for current employees were not being recovered by RUS and the PMAS. We determined that Federal Employee Retirement System (FERS) pension benefits are currently being fully funded by employee and employer contributions.

To calculate the cost of CSRS pension benefits that were not fully recovered by RUS from borrowers or by the PMAS and TVA from rate payers, and the cost of postretirement health benefits that were not fully recoverd by RUS from borrowers or by the PMAS from ratepayers, we reviewed SFFAS No. 5, Accounting for Liabilities of the Federal Government, which requires all federal agencies to record the full cost of pension and postretirement health benefits in financial statements beginning in fiscal year 1997.

SFFAS No. 5 prescribes that the aggregate entry age normal (AEAN)[14] actuarial cost method be used to calculate pension expenses. We consulted with actuaries from the Office of Personnel Management (OPM) to obtain an understanding of how to apply the AEAN method to estimate the amount by which employer and employee contributions toward future CSRS pension benefits fall short of the normal cost of those benefits.

We determined the applicable normal cost, under the AEAN method, of CSRS pensions for fiscal year 1996. For CSRS employees, OPM reported that in 1996, 25.14 percent of gross salaries was the full (normal) cost to the federal government of benefits earned that year by employees and that federal agencies contributed 7 percent and employees contributed 7 percent to OPM for CSRS, leaving a funding deficiency of 11.14 percent of

[14]Under the AEAN method, which is based on dynamic economic assumptions, including future salary increases, the actuarial present value of projected benefits is allocated on a level basis over the earnings or the service of the group between entry age and assumed exit ages and should be applied to pensions on the basis of a level percentage of earnings. The portion of this actuarial present value allocated to a valuation year is called the "normal cost."

each CSRS employee's annual salary. This 11.14 percent funding deficiency is applicable to federal agencies. To calculate the difference between the full (normal) cost for CSRS pensions and the amount employees and the federal entities contributed, we

- estimated the number of full-time equivalent positions involved in electricity-related activities at RUS, the PMAs and TVA, based on information provided by each entity;
- estimated the number of those employees covered by the CSRS pension plan, based on (1) governmentwide information provided by OPM on the percentage of employees covered by CSRS or (2) information provided by the entity;
- multiplied that number by the average salary[15] to estimate total CSRS payroll expense; and
- multiplied the resulting number by 11.14 percent, which, according to OPM actuaries, represents the difference between the normal cost of future CSRS pensions and combined employer and employee contributions.

The result is an estimate of the additional amount the entities would have had to contribute to fully fund CSRS pension benefits earned in fiscal year 1996.

To estimate the cumulative net costs for fiscal years 1992 through 1996 under the AEAN method for future CSRS pensions, we multiplied the net cost for 1996 by five. The resulting estimate of cumulative net costs for CSRS pensions for the 5-year period, which we converted to constant 1996 dollars, is conservative because the number of CSRS employees has been declining. The annual net cost, or funding shortfall, associated with CSRS pension benefits will be eliminated over time as CSRS employees leave the government and are replaced with FERS employees, provided that FERS pension benefits remain fully funded.

In addition to pensions, federal employees are eligible to receive postretirement health coverage, for which a portion of the premium is paid by the federal government. While employed, neither federal employees nor their employing agencies contribute funds to pay for the federal government's portion of postretirement health benefits. For applicable employees, the PMAs do not recover this cost from ratepayers, and RUS does not recover this cost from borrowers. To calculate the amount of the electricity-related costs for fiscal year 1996, we again used the AEAN method, which is prescribed by SFFAS No. 5 for estimating postretirement

[15]We used governmentwide average salary information we obtained from OPM for CSRS employees.

health benefit costs. We estimated the number of relevant covered employees at each entity involved in electricity-related activities. We multiplied this number for each employee by the 82-percent governmentwide health benefits plan participation rate, which we then multiplied by $2,183 (OPM's estimate of the annual normal cost for postretirement health benefits per participating employee for fiscal year 1996). The result of this calculation approximates the normal cost of postretirement health benefits for fiscal year 1996 and the amount the entities would have had to contribute to fully fund postretirement health benefits earned that year. As with CSRS pensions, to estimate the cumulative net costs for fiscal years 1992 through 1996, we multiplied the net cost for 1996 by five, and converted this amount to constant 1996 dollars.

It is important to note that our calculations of annual pension and postretirement health benefits do not include any provision for retirees of each entity because the relevant actuarial information needed to do so was not available from OPM.

Assessing the Recovery of Other Costs

For this report, we defined other costs to include construction costs for certain projects, environmental costs legislatively precluded from recovery, power-related costs assigned to incomplete irrigation projects, deferred payments, interest expense on store supplies, legal costs incurred by the Department of Justice, and administrative appropriations not recovered. As discussed below, to assess these costs we used audited financial statements, cost reports, and/or other provided information. Not all of the costs were applicable to each agency.

We obtained information on recovery of construction costs relating to the Teton Project (BPA), Russell Project (Southeastern), Truman Project (Southwestern), and the Washoe and Mead-Phoenix Projects (Western), by analyzing the PMA annual reports and other information provided by the PMAs and operating agencies. For the Corps' Russell Project, we also reviewed records of congressional hearings on the project dating back to its initial approval in the 1960s.

We used cost reports and financial statements from the PMAs and operating agencies to review environmental costs. We determined that some environmental costs have been legislatively excluded from recovery in rates. We also found some environmental costs not legislatively excluded that are included in rates, but we could not determine whether all such costs are included. Obtaining the data necessary to make this determination was beyond the scope of the assignment.

To identify the portion of power-related capital costs allocated to incomplete and unfeasible irrigation facilities at Western's Pick-Sloan program, we used (1) cost reports and estimates of the power requirements for irrigation facilities prepared by the Bureau, (2) cost allocation percentages prepared by the Bureau and Corps, and (3) reconciliations prepared by Western in their Power Repayment Studies and the Bureau's Statement of Project Construction Cost and Repayment as of September 30, 1994. We determined that the capital costs allocated to incomplete or unfeasible irrigation facilities amounted to about $454 million as of September 30, 1994. Based on our previous finding that these capital costs increased by about $5 million annually between fiscal years 1987 and 1994,[16] we estimated that the capital costs amounted to about $464 million as of September 30, 1996. We did not verify the Bureau's cost-benefit calculations for determining the feasibility of its irrigation projects within the Pick-Sloan program.

To identify the portion of the Corps power-related operations and maintenance (O&M) expenses that Western has allocated to incomplete irrigation facilities for financial reporting and cost recovery purposes, we reviewed the annual calculations made by Western to allocate the Corps of Engineers' annual O&M expenses based on the planned rather than the actual use of the irrigation facilities.

Western has had an outstanding balance of deferred interest and O&M payments since at least 1988. Within the last 5 fiscal years, the amount deferred ranged from a high of $250 million as of September 30, 1994, to a low of $81 million as of September 30, 1996. To assess the impact on Treasury, we analyzed the net change in the deferred payments amount in each of the last 5 years. Net increases in the deferred amount in fiscal years 1992 through 1994 were reflected as net costs to the federal government. Net decreases in the deferred amount in fiscal years 1995 and 1996 were reflected as net recoveries for the federal government.

Western has maintained an inventory of "stores supplies" (spare parts used in performing maintenance, repairs, and upgrades of transmission facilities), averaging almost $21 million over the 5 years from 1992 through 1996. However, Western has not paid interest on the appropriated debt

[16] Federal Power: Recovery of Federal Investment in Hydropower Facilities in the Pick-Sloan Program (GAO/T-RCED-96-142, May 2, 1996).

associated with this inventory. We estimated the amount of interest that was not paid to Treasury each year by multiplying the stores supplies balance as of September 30 of each of the last 5 fiscal years by the average yield rate on 3-year marketable Treasury bonds issued in each of those years. We used the 3-year bond rate because the stores inventory turns over about once every 2 or 3 years.

We assessed the recovery of legal costs the Department of Justice (DOJ) incurs on behalf of RUS. We determined that DOJ's legal costs are not charged to RUS and are thus costs that the federal government incurs on RUS' behalf. To identify DOJ's legal costs for RUS, we obtained information from DOJ for fiscal years 1992 through 1996. These costs include staff hours, salaries, benefits, travel, and other costs. We also found that BPA and DOJ have an intergovernmental agreement in place that provides for DOJ to bill BPA for certain costs incurred. The agreement specifically covers BPA's Washington Public Power Supply System and Tenaska litigation, as well as DOJ's salary, travel, and certain other costs. We did not assess whether this arrangement results in the full recovery of costs DOJ incurs for BPA.

We determined from discussions with USDA officials that RUS does not recover administrative appropriations through interest or other charges to borrowers. To identify the electricity-related share of RUS' administrative appropriation for fiscal years 1992 through 1996, we obtained an estimate from USDA. According to USDA, these administrative costs include funding for all direct and indirect costs, except the pension and postretirement health benefits previously discussed.

Assessing the Risk to the Federal Government of Future Losses for Electricity-Related Activities

In assessing the risk of future losses beyond the net recurring costs to the federal government from the electricity-related activities at the PMAS, TVA, and RUS, we used the criteria for contingencies from SFFAS No. 5, Accounting for Liabilities of the Federal Government. According to SFFAS No. 5, "A contingency is an existing condition, situation, or set of circumstances involving uncertainty as to possible gain or loss to an entity. The uncertainty will ultimately be resolved when one or more future events occur or fail to occur." When a loss contingency exists, the likelihood that the future event or events will confirm the loss or the incurrence of a liability can range from probable to remote as follows:

- *Probable*: The future confirming event or events are more likely than not to occur.

- *Reasonably possible*: The chance of the future confirming event or events occurring is more than remote but less than probable.
- *Remote*: The chance of the future event or events occurring is slight.

We applied these criteria and considered different risk factors on the basis of discussions with agency officials and industry experts, analysis of financial and other data, and our professional judgment. It is important to note that our assessment of the likelihood of loss does not generally consider proceeds that the federal government would receive from the sale of the assets of the RUS borrowers, the PMAS, or TVA.

Assessing Risk of Loss to the Federal Government for the Rural Utilities Service Portfolio of Electric Loans and Loan Guarantees

In order to assess the risk of future loss beyond the net recurring costs to the federal government from the electricity-related activities of RUS, we reviewed the $32.3 billion (as of September 30, 1996) RUS portfolio of electric loans and loan guarantees outstanding to rural electric cooperatives. The portfolio consists of loans and guarantees made to 782 distribution cooperatives and 55 Generation and Transmission (G&T) cooperatives. We focused primarily on the G&TS, since their principal outstanding is approximately $22.5 billion, or about 70 percent of the RUS electric loan portfolio, and they are generally higher risk loans. According to RUS officials, the G&T borrowers generally have substantial capital investment and debt and thus have higher-risk loans than those made to distribution borrowers. The G&TS are wholesale producers and are more vulnerable to current competitive pressures. In addition, 19 of the 55 G&T borrowers have invested in uneconomical nuclear projects.

We contacted Moody's Investors Service to obtain their views on the risk of loss from the RUS portfolio and to gain an understanding of issues facing the cooperatives. We reviewed the list of 13 G&T borrowers that RUS has identified as financially stressed. According to RUS reports, about $10.5 billion of the $22.5 billion in G&T debt is owed by the 13 financially stressed borrowers. We ascertained from RUS why each of the 13 was placed on the list. Of these, four G&T borrowers are in bankruptcy with about $7 billion in outstanding debt. The remaining 9 borrowers have investments in uneconomical nuclear generating plants and/or have requested or plan to request financial assistance from RUS. We obtained and reviewed agency documents with write-off information for fiscal years 1992 through 1996. We also discussed with RUS and DOJ officials the loan write-offs to date, the 13 financially stressed borrowers, and the potential for future write-offs.

To assess the ability of RUS G&T cooperatives to withstand competitive pressures, we analyzed the average revenue per kilowatthour (kWh) of 33 G&T borrowers that are not currently considered financially stressed by RUS. We excluded the 9 G&Ts that only transmit electricity and the 13 financially stressed borrowers. As of September 30, 1996, the loans outstanding for these 33 G&Ts were about $11.7 billion of the $22.5 billion in G&T loans outstanding. We compared the average revenue per kWh for these borrowers with North American Electric Reliability Council (NERC) regional averages for investor-owned utilities (IOUs) and publicly-owned generating utilities (POGs). We obtained the average revenue per kWh for the 33 borrowers from RUS statistical reports and verified the numbers to the borrowers' annual reports and the borrowers' audited financial statements, when available. In addition, RUS staff verified the numbers. We obtained a report on electric cooperatives from Moody's Investors Service, which corroborated our data. (See appendix III for a further discussion of average revenue per kWh.)

Assessing Risk of Future Loss to the Federal Government for the PMAs and TVA

To assess the risk of future loss beyond the net recurring costs to the federal government from the electricity-related activities of the PMAs and TVA, we analyzed each agency based on several key factors. We interviewed government bond analysts at Fitch Investors Service and at Moody's to determine the factors they use to analyze the financial condition of electric utilities and provide bond ratings. The specific factors that we used to analyze each agency included cost of electricity production and rates, key financial ratios, generating mix, competitive environment, management actions, and legislative and other factors. Because of the unique characteristics of each PMA and TVA, not all factors were applicable to each agency. We also identified mitigating factors that reduce the probability of loss for each agency. Based on our assessment of the risks and mitigating factors, we determined whether the risk of future loss beyond the net recurring costs to the federal government was probable, reasonably possible, or remote. For BPA, we assessed the risk of loss (1) through the year 2001 and (2) after the year 2001. For TVA, we assessed the risk of loss (1) with protections from competition and (2) without barriers to competition.

To assess the competitiveness of the PMAs and TVA, we compared the average revenue per kWh for wholesale sales of each entity to the average revenue per kWh for wholesale sales of IOUs and POGs in the primary NERC region that each entity operates. We also compared the average revenue per kWh of each of the three PMAs' rate-setting systems to IOUs and POGs in each system's NERC region.[17] We determined that IOUs and POGs were the appropriate "industry group" to compare to the PMAs and TVA because they generate and transmit electricity and sell some power at wholesale. Our comparisons are particularly relevant because many power customers are primarily concerned with cost of production and resultant electricity rates when choosing their electricity suppliers. We did not include nongenerating publicly owned utilities. These utilities ordinarily have no generating assets and thus are not comparable from an operating or financial perspective.

To assess the flexibility of BPA and TVA to respond to competitive pressures, we computed the ratio of financing costs to revenue for each entity and nonfederal utilities by dividing financing costs by operating revenue. The financing costs include interest expense on short-term and long-term debt, appropriated debt for BPA and TVA, and preferred and common stock dividends for the IOUs. Preferred and common stock dividends were included in the IOUs' financing costs to reflect the difference in the capital structure of these entities from BPA and TVA. We also computed the ratio of fixed financing costs to revenue for TVA and neighboring IOUs. For TVA, we limited our comparison group to 11 IOUs[18] that border on TVA's service area because industry experts told us that due to the cost of transmitting electricity, TVA's competition would most likely come from IOUs located close to its service area. For example, the Bristol Virginia Utilities Board has terminated its power contract with TVA and agreed to purchase its electric power from Cinergy, one of the IOUs in our comparison group. We calculated this ratio by dividing financing costs less common stock dividends by operating revenue for the fiscal year. We excluded common stock dividends from the IOUs' financing costs because they are not contractual obligations that have to be paid.

To assess changes in the environment in which BPA operates and potential measures that may be taken in response to these changes, we reviewed the final report from the Comprehensive Review of the Northwest Energy System that was initiated by the governors of the states that BPA serves.

[17]Unlike the three PMAs, BPA is comprised of a single rate-setting system.

[18]The 11 IOUs and their subsidiary utilities used in our comparison included (1) American Electric Power Company (including Appalachian Power, Columbus Southern Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, and Wheeling Power), (2) Carolina Power & Light Company, (3) Cinergy Corp. (including Cincinnati Gas & Electric and PSI Energy), (4) Dominion Resources, Inc. (including Virginia Electric Power), (5) Duke Power Company, (6) Entergy Corporation (including Arkansas Power & Light, Gulf States Utilities, and Mississippi Power & Light), (7) Illinova Corporation (including Illinois Power), (8) KU Energy Corp. (including Kentucky Utilities Co.), (9) LG&E Energy Systems (including Louisville Gas and Electric), (10) SCANA Corporation (including South Carolina Electric & Gas), and (11) The Southern Company (including Alabama Power, Georgia Power, Gulf Power, and Mississippi Power).

Since the review's recommendations have not been implemented, we did not assess the effect they would have on the federal government's financial risk. In addition, we examined the extent to which BPA's financial reserves provide additional flexibility in BPA's attempts to respond to competitive pressures. We did not, however, perform an independent evaluation of BPA's $325 million fish contingency reserve or the credits BPA takes annually for fish migration costs.

To compare the amount of deferred assets and capital costs that TVA has compared to neighboring IOUs, we computed the following two ratios for 1996.

- The ratio of accumulated depreciation and amortization to gross property, plant and equipment (PP&E) was calculated by dividing accumulated depreciation and amortization by gross PP&E at fiscal year-end.
- The ratio of deferred assets to gross PP&E was calculated by dividing deferred assets by gross PP&E at fiscal year-end. Deferred assets include construction work-in-progress and deferred nuclear units (for TVA only). Deferred nuclear units are included for TVA because they are treated by TVA as construction work-in-progress (that is, not depreciated).

To compute the investment in utility plant per megawatt of generating capacity for the PMAS, TVA, and nonfederal utilities, we divided gross PP&E by the utilities' generating capacity at fiscal year-end. For the IOUs, we used the nameplate generating capacity at fiscal year-end 1995. For TVA, we used the winter net dependable generating capacity as of September 30, 1996. We used TVA's capacity figure as of September 30, 1996, to reflect the two nuclear units that TVA brought on line during fiscal year 1996. For the IOUs, we computed average system retail rates by dividing total retail electricity revenues by total kilowatt hours sold. To calculate the average system retail rates[19] for TVA, we multiplied the percentage of retail sales by TVA's residential, commercial, and industrial sales by the retail sales for each category. Then, we totaled these amounts to compute the weighted average system retail rate for TVA.

To assess the status of TVA's power program, we examined the history and current operation of TVA's nuclear power program and TVA's prospects for converting the partially completed Bellefonte Nuclear Plant to a fossil plant. We focused on TVA's nuclear power program because it is associated with a substantial portion of TVA's $27.9 billion of debt, and because it has

[19]TVA sells wholesale power to its distributors who then sell it at retail rates. In performing this calculation, we used TVA's distributors' retail rates.

experienced problems over the past 20 years. We reviewed previous GAO, TVA, and Nuclear Regulatory Commission reports on TVA's nuclear power program. We examined TVA's program for operating, maintaining, and upgrading its nonnuclear power assets, primarily its coal-fired and hydroelectric units. The coal-fired and hydroelectric units are important because in fiscal year 1996, approximately 65 percent of TVA's generation was from coal-fired units and 11 percent was from hydroelectric units. For the coal-fired and hydroelectric units, we reviewed TVA's projected capital expenditures through the year 2001. We obtained data on TVA's plans to upgrade or retire these units and its assessments of the costs of complying with environmental requirements, including the Clean Air Act requirements.

To gain an understanding of the concerns of the PMAS' customers, we contacted organizations representing major PMA customers. These groups were formed to facilitate communication between the PMAS and their customers and to raise concerns where appropriate. For all four PMAS, we obtained the groups' perspectives on the impact of deregulation on the electricity industry. For BPA, we also obtained the groups' viewpoints on the reasonableness of BPA's attempts to renew contracts with existing customers before they expire in 2001. Because most of our concerns with Southeastern, Southwestern, and Western relate to individual rate-setting systems, we specifically addressed issues related to these systems' competitiveness with the appropriate customer group. Where the customer group corroborated information from the three PMAS on the competitiveness of an individual rate-setting system, we did not independently verify it, and we attributed any views reported.

To gain an understanding of the concerns of TVA's customers, we contacted regional associations that represent TVA's distributors and large industrial customers. We also interviewed officials from some of TVA's largest distributors (which represent over 30 percent of TVA's energy sales), including the municipal utilities of Chattanooga, Knoxville, Memphis, and Nashville, Tennessee. We interviewed officials from the Bristol, Tennessee, and Fort Payne, Alabama, utilities in order to gain the perspectives of TVA's smaller municipal distributors. We also interviewed officials from the Bristol Virginia Utilities Board because the utility has terminated its power contract with TVA and agreed to purchase its electric power from another utility beginning January 1, 1998. We interviewed officials from the Four County Electric Power Association in Columbus, Mississippi, because the utility had terminated its power contract with TVA, but the utility subsequently withdrew its termination notice and decided to remain in the TVA system. We analyzed the provisions of TVA's power contracts to determine how difficult it would be for a distributor to cancel its contract. We examined recent modifications that some distributors have made to the cancellation notice requirements in their contracts. We also examined recent agreements not to exercise termination rights that some distributors have signed.

A list of the organizations that we contacted during the course of our work follows. We conducted our review between January 1997 and July 1997 in accordance with generally accepted government auditing standards. We obtained written comments on a draft of our report, which are contained in appendixes X through XIII.

Organizations That GAO Contacted

The following are the organizations that GAO contacted during the course of its work.

Federal Agencies

Congressional Budget Office
Department of Agriculture, Office of the Inspector General and Rural Utilities Service
Department of Defense, U.S. Army Corps of Engineers
Department of Energy, including the Energy Information Administration and Office of the Inspector General
Department of the Interior, Bureau of Reclamation
Department of Justice
Department of Treasury, including the Federal Financing Bank
Nuclear Regulatory Commission, Atlanta Region
Office of Management and Budget
Office of Personnel Management, Office of Actuaries

Bond Rating Agencies

Fitch Investors Service, Inc., New York, New York
Moody's Investors Service, New York, New York

Independent Public Accounting Firms

Coopers & Lybrand L.L.P.
KPMG Peat Marwick LLP
Price Waterhouse LLP
Urbach Kahn and Werlin P.C.

Electric Utilities or Holding Companies

Entergy, New Orleans, Louisiana
Southern Company, Atlanta, Georgia

Customer Representative or Trade Groups

Direct Service Industries, Inc., Portland, Oregon
Electric Power Supply Association, Washington, D.C.
Northern California Power Agency, Palo Alto, California
Northwest Irrigation Utilities, Portland, Oregon
Northwest Requirements Utilities, Portland, Oregon
Pacific Northwest Utilities Conference Committee, Portland, Oregon
Public Power Council, Portland, Oregon
Southeastern Federal Power Customers, Alabama
Southwestern Power Resources Association, Tulsa, Oklahoma
Tennessee Valley Energy Reform Coalition, Knoxville, Tennessee
Tennessee Valley Industrial Committee/Associated Valley Industries, Columbia, Tennessee
Tennessee Valley Public Power Association, Chattanooga, Tennessee

TVA Distributors

Bristol, Virginia
Bristol, Tennessee
Chattanooga, Tennessee
Four County Electric Power Association, Columbus, Mississippi
Fort Payne, Alabama
Knoxville, Tennessee
Memphis, Tennessee
Nashville, Tennessee
Paducah, Kentucky

Average Revenue Per Kilowatthour for Wholesale Sales

Average Revenue Per Kilowatthour Is an Indicator of Power Production Costs

In a competitive market for a relatively homogeneous product like electricity, being among the lowest cost producers is generally the most important factor in determining competitive position. As the electricity industry responds to deregulation, the ability to keep power production costs low will enhance an entity's competitive position. To assess power production costs, we examined the average revenue per kilowatthour (kWh) for each entity in our report.

The average revenue per kWh for wholesale sales (sales for resale) is referred to as average revenue per kWh. The average is calculated by dividing total revenue from the sale of wholesale electricity by the total number of wholesale kilowatthours sold. Because the power marketing administrations (PMAs), publicly-owned generating utilities (POGs), and rural electric cooperatives generally recover costs through rates with no profit, average revenue per kWh should reflect the power production costs of the PMAs, POGs, and rural electric cooperatives. This assumes that the entity's competitive position is such that it can charge sufficiently high rates to recover all costs from customers. For investor-owned utilities (IOUs), average revenue per kWh should reflect cost plus the regulated rate of return. Given that a large portion—an average of 79 percent over the last 5 years—of IOU rate of return (net income) is paid out in common stock dividends, which is a financing cost, average revenue per kWh also approximates power production costs for IOUs.

The Energy Information Administration (EIA) cautions that average revenue per unit of energy sold should not be used as a substitute for the price of power. The price that any one utility charges for wholesale energy comprises numerous transaction-specific factors, including the fees charged for reserving a portion of capacity, consumption during peak and off-peak periods, and the use of the facilities. These fees are influenced by factors such as time of delivery, quantity of energy, surcharges, and reliability of supply. For example, some Western project revenues include a legislatively mandated surcharge that is not related to production costs.

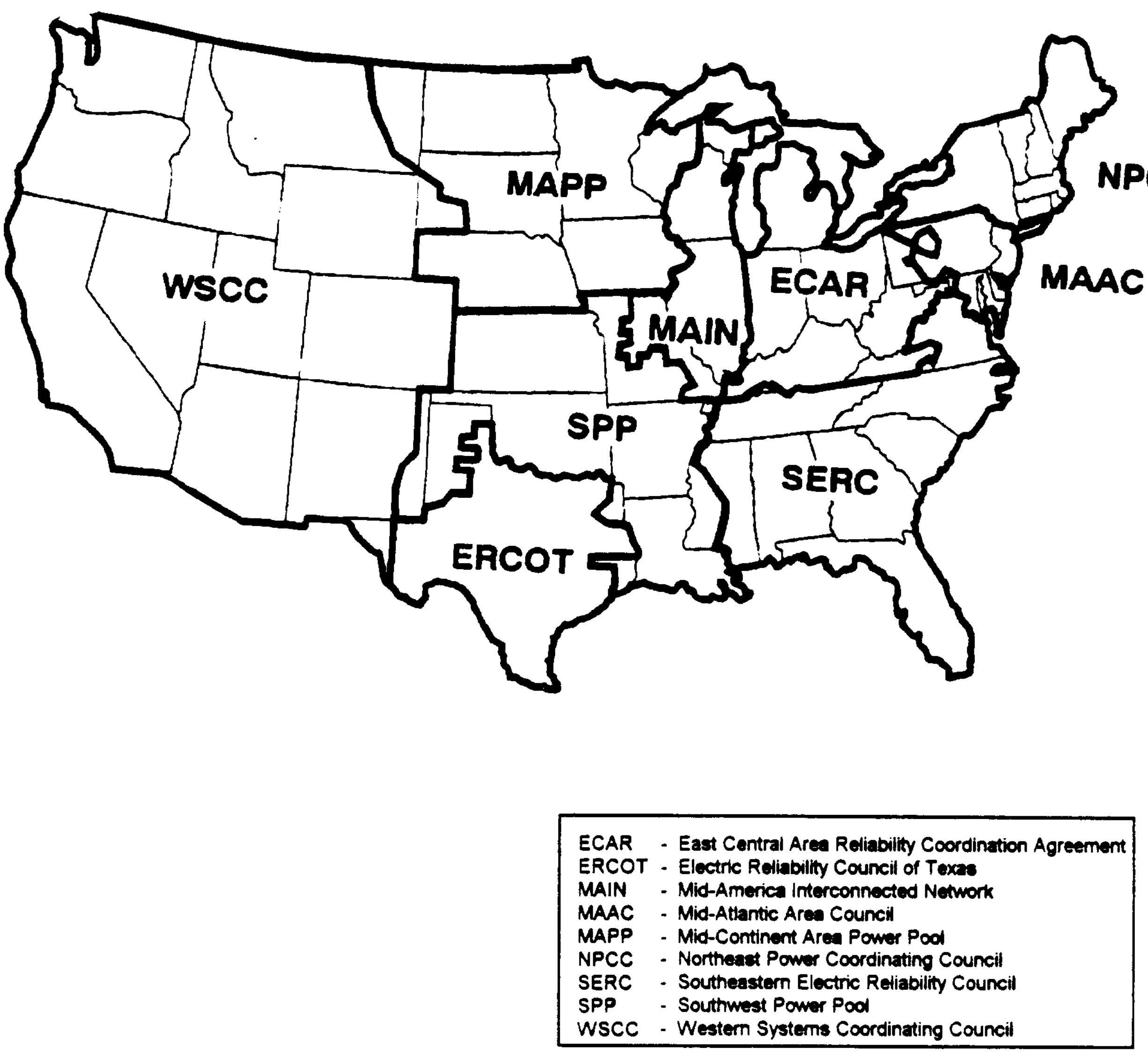
In the current electricity market, utilities generally are able to recover their fixed costs from captive retail customers. When competing for new wholesale customers, utilities with excess capacity that are able to recover their fixed costs from retail customers are able to sell excess output at a price that does not reflect the full cost of producing that electricity (i.e., they can sell that power at marginal cost). Consequently, in some cases average revenue per kWh may not reflect full power production costs. However, despite these limitations, average revenue per kWh is a good indicator of production costs since over time utilities must recover all costs to remain in business. We therefore believe that average revenue per kWh reflects today's competitive environment. In addition, bond rating services such as Moody's Investors Service use average revenue per kWh as one factor to assess competitive position.

In volume 1 and appendixes VI, VII, and VIII, we compare the average revenue per kWh for RUS Generation and Transmission Cooperatives (G&T) borrowers, the three PMAs, and BPA to the North American Electric Reliability Council (NERC)[1] regions in which they operate because the factors related to individual entities' regional markets are still the key determinant of the competitive position of each entity. NERC consists of 10 regional reliability councils[2] and encompasses essentially all the power systems of the contiguous United States, as well as parts of Canada and Mexico. Because the latest available data on average revenue per kWh by NERC region are for 1995, we used the 1995 NERC configuration, which shows only nine councils. A new regional council that encompasses much of Florida was added in 1996. Figure III.1 illustrates the location of the NERC regions of the contiguous United States as of 1995.

[1]NERC was formed by the electric utility industry to promote the reliability and adequacy of the bulk power supply in the electric utility systems of North America.

[2]In addition to its 10 regional councils, NERC has 1 affiliate council member, the Alaska Systems Coordinating Council (ASCC).

Figure III.1: NERC Regions of the Contiguous United States, as of 1995



Source: North American Electric Reliability Council.

Summary of Net Costs

The net costs to the federal government resulting from its involvement in the electricity-related activities of four of the Department of Energy's power marketing administrations (PMAS),[1] Tennessee Valley Authority (TVA), and the Department of Agriculture's Rural Utilities Service (RUS) are summarized in table IV.1. The first four categories of net costs (net financing, loan write-offs, pensions and postretirement health benefits, and construction) are discussed in volume 1 of this report. The remaining categories are referred to as "Other" net costs in volume 1 and are briefly explained below. See appendix II for a discussion of our methodology for estimating the net costs. Also see our September 19, 1996, report for additional information regarding some of these costs.[2]

Table IV.1: Net Costs for Fiscal Year 1996 and Fiscal Years 1992 Through 1996 in Constant 1996 Dollars for RUS, TVA, and the PMAs

Dollars in millions

							Total Costs	
	RUS	TVA	BPA	SEPA	SWPA	WAPA	1996	1992-1996 (Constant 1996 dollars)
Net financing	$874		$377	$68	$42	$98	$1,459	$6,941
Loan write-offs	982						982	1,049
Benefits	1	$1	21	3	2	11	39	199
Construction				30			30	139
Environmental						28	28	144
Deferred payments						(114)	(114)	(74)
Administrative appropriations	21						21	110
DOJ costs								1
Irrigation						16	16	80
Stores inventory						1	1	6
Total	**$1,878**	**$1**	**$398**	**$101**	**$44**	**$40**	**$2,462**	**$8,597**

Note: Totals may not add due to rounding.

Net Financing Costs

For RUS, the net financing cost represents the difference between the annual interest income received by the federal government from RUS

[1]The PMAs are Bonneville, Southeastern, Southwestern, and Western Area Power Administrations, which are referred to as BPA, SEPA, SWPA, and WAPA, respectively.

[2]Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, September 19, 1996).

borrowers and the federal government's annual interest expense to provide the funds. For the PMAS, the net financing cost represents the difference between interest income received by the federal government on appropriated debt and the federal government's related interest expense. See appendix II for a further description of the methodologies used in estimating net financing costs and appendix V for more information about RUS' net financing costs.

Loan Write-offs

RUS has recently written off a substantial dollar amount of loans to rural electric cooperatives under Department of Justice (DOJ) authority. RUS wrote off about $982 million of debt in fiscal year 1996 and a total of about $1.05 billion (in constant 1996 dollars) over the 5-year period 1992-1996. In addition, at the time of our review, RUS had written off $502 million in fiscal year 1997. The most significant write-offs are related to Generation and Transmission Cooperatives (G&T) borrowers. See volume 1 of this report for more information.

Pension and Postretirement Health Benefits

RUS, the PMAS, and TVA[3] do not recover the full costs to the federal government of providing Civil Service Retirement System (CSRS) pension benefits to current federal employees. Nor do RUS and the PMAS recover the full costs to the federal government of providing postretirement health benefits to current federal employees. We estimate that the net CSRS pension and postretirement health benefit cost totaled about $39 million in fiscal year 1996 and about $199 million in constant 1996 dollars over the 5-year period 1992-1996.[4]

Construction Costs

Construction costs are comprised of interest that is not paid to Treasury each year for two construction projects. As discussed in appendix VII, interest is capitalized each year on the nonoperational portion of the Russell Project, marketed by Southeastern. The unrecovered interest totaled about $30 million in fiscal year 1996 and about $138 million (in constant 1996 dollars) over the 5-year period 1992-1996. In addition, interest was not paid to Treasury on the money spent to construct the

[3]TVA has a small number of employees who transferred to TVA from federal agencies and continued to be covered by federal pension programs—CSRS or the Federal Employees Retirement System (FERS). TVA has its own pension system, which is fully funded. TVA employees are not covered by the Federal Employees Health Benefits Program (FEHBP).

[4]Our analysis covered pension and postretirement health benefit costs for current employees only. The costs associated with retired employees were not considered because the data necessary to do so was not available from the Office of Personnel Management (OPM).

Teton Dam, which would have been marketed by BPA. The Teton Dam failed in 1976 when construction was nearly complete. The Teton costs have been carried on the Bureau of Reclamation's books as construction work-in-progress even though construction was halted 20 years ago, and no interest has accrued since 1976. The unrecovered interest related to the Teton Dam totaled about $236,000 in fiscal year 1996 and about $1.2 million (in constant 1996 dollars) over the 5-year period 1992-1996.

Environmental Mitigation Costs

Two projects, the Central Valley Project's Shasta Dam and the Colorado River Storage Project's Glen Canyon Dam, have incurred power-related environmental mitigation costs that have been legislatively excluded from Western's power rates. The 1991 Energy and Water Development Appropriations Act specified that any increases in purchased power at the Shasta Dam caused by bypass releases related to fisheries preservation in the Sacramento River not be allocated to power. Western officials believe that the bypass releases will be eliminated or minimized by the construction of a temperature control device at the Shasta Dam, which was recently completed. These net costs totaled about $15.3 million in fiscal year 1996 and about $53.8 million (in constant 1996 dollars) over the 5-year period 1992-1996.

The Grand Canyon Protection Act of 1992 exempted from recovery certain costs of mitigating the environmental impact of river flow fluctuations at the Glen Canyon Dam. The act states that certain costs of environmental impact studies related to the Glen Canyon Dam are not to be repaid by power customers, but it includes a provision that these costs could become the responsibility of the power customers under certain circumstances. The power-related costs for environmental mitigation at the Glen Canyon Dam totaled about $12.8 million in fiscal year 1996 and about $90.3 million (in constant 1996 dollars) over the 3-year period since the legislative exemption, 1994-1996.

Deferred Payments

As of September 30, 1996, Western had deferred operations and maintenance (O&M) and interest expense payments totalling about $81 million. This balance was $114 million less than the $195 million outstanding as of September 30, 1995. Because of the net repayments in fiscal years 1995 ($56.2 million in constant 1996 dollars) and 1996 ($114 million) of interest and O&M expenses deferred in prior years, the deferred payment figures in table IV.1 are negative.

Deferred payments are to be repaid to Treasury, with interest. Western officials expect to recover the majority of the deferred payments outstanding as of September 30, 1996, over time.

Administrative Appropriations

The annual administrative appropriation to RUS includes salary expenses for RUS employees as well as travel, data processing, and other administrative support expenses. These costs are not passed on to RUS borrowers. The estimated electricity-related share of the RUS administrative appropriation was about $21 million in fiscal year 1996 and about $110 million (in constant 1996 dollars) over the 5-year period 1992-1996.

Department of Justice Costs

The DOJ costs primarily represent hours worked by DOJ attorneys on litigation related to RUS' electricity-related activities. In 1996, DOJ attorneys spent about 5,700 hours working on RUS cases. These costs are not charged to RUS and therefore are not passed on to RUS borrowers. Judiciary costs related to RUS include salaries and benefits received by DOJ attorneys and expenses for travel, printing, and expert witnesses. We estimate that DOJ's total judiciary costs on behalf of RUS were about $453,000 in fiscal year 1996 and about $1.4 million (in constant 1996 dollars) over the 5-year period 1992-1996.

Irrigation

Substantial capital costs for hydropower facilities and water storage reservoirs of the Pick-Sloan Missouri Basin Program have been allocated to authorized irrigation facilities that are incomplete and infeasible. Western is currently selling electricity to power customers that irrigators would have used if the irrigation projects had been completed. If the costs had been allocated based on actual use, they would have been allocated primarily to power and recovered through power rates within 50 years, with interest. We estimate that these capital costs—which we previously reported increased by an average of nearly $5 million annually between fiscal years 1987 and 1994,[5]—totaled about $464 million as of September 30, 1996.

Interest on the $464 million in capital expenditures is not being paid. Using the 3 percent interest rate that was in effect for power projects when construction began, we estimate that the net interest cost was about

[5] Federal Power: Recovery of Federal Investment in Hydropower Facilities in the Pick-Sloan Program (GAO/T-RCED-96-142, May 2, 1996).

$13.8 million in fiscal year 1996 and about $70.6 million (in constant 1996 dollars) over the 5-year period 1992-1996. In addition, annual O&M expenses that otherwise would have been allocated primarily to power and repaid from electricity rates have also been allocated to the incomplete irrigation facilities. If these expenses had been allocated to power, they would have been included in Western's annual O&M expenses and recovered from power customers. We estimate that the net irrigation O&M expense was about $2.1 million in fiscal year 1996 and about $9.8 million (in constant 1996 dollars) over the 5-year period 1992-1996.

Stores Inventory

Western has maintained an inventory of "stores supplies," which are spare parts used in performing maintenance, repairs, and upgrades of transmission facilities, averaging almost $21 million over the 5-year period 1992-1996. As noted by Western's external financial auditor, Western has not paid interest to Treasury on the amount of money spent to purchase this inventory. However, in response to our questions, Western officials stated that they will begin recovering interest on the stores supplies in fiscal year 1997. We estimate that the net interest expense associated with the stores supplies was about $1.2 million in fiscal year 1996 and about $6.1 million (in constant 1996 dollars) over the 5-year period 1992-1996.

Rural Utilities Service's Net Financing Cost

A net financing cost exists in the Rural Utilities Service (RUS) electric program because the annual interest income received from RUS borrowers is substantially less than the federal government's annual interest expense to provide the funds to the electric borrowers. Interest income is affected by favorable rates and terms given to some borrowers and also by financially troubled RUS borrowers who have missed scheduled loan payments. According to RUS reports, about $10.5 billion is owed by 13 financially stressed wholesale producers that we refer to as Generation and Transmission Cooperatives (G&T) borrowers. See appendix VI for a risk assessment of the RUS loan portfolio.

As shown in table V.1, using the portfolio methodology discussed in appendix II, we estimate that net financing costs (interest expense minus interest income) to the federal government for the RUS electric program for fiscal year 1996 were about $874 million; cumulatively, over the last 5 years, we estimate that the net financing costs totaled about $3.8 billion (in constant 1996 dollars). These net financing costs reflect net interest expense incurred by Treasury in providing the funding for RUS electric loans; therefore, they do not correspond to RUS appropriations for these years.

Table V.1: Financing Costs to the Government

Dollars in millions

	1996	1992-1996 (Constant 1996 dollars)
Interest income		
Electric loans	$1,853	$10,813
Interest expense		
Debt to U.S. government (FFB/Treasury)	2,477	13,396
Debt to private lenders	250	1,229
Net financing costs	**$(874)**	**$(3,812)**

Interest Income

RUS interest income is initially affected by favorable loan rates given to some borrowers compared to the government's cost of borrowing. Until the Rural Electrification Act was amended in 1973, almost all financing was through direct loans from the Rural Electrification Administration (REA) to electric borrowers at a fixed rate of 2 percent with maturities up to 35 years. However, the 1973 amendment to the act increased the interest rate on the direct loans from 2 percent to 5 percent. At the same time, loans were also made available (through REA) to borrowers from the newly created Federal Financing Bank (FFB) at the cost of money to the government. In 1993, the act was amended again, and the direct loan standard rate of 5 percent was changed to provide direct loans with an interest rate that is (1) tied to an index of municipal borrowing rates or (2) fixed at 5 percent. Most loans are now made at the municipal rate with or without a 7-percent cap. Certain borrowers with customers that have low consumer and household incomes and high residential retail rates qualify for a loan at the 5-percent hardship interest rate. See appendix I for a description of RUS' electric loans.

In addition to the favorable interest rates received by some borrowers, RUS interest income is also affected by financially stressed borrowers' failure to make scheduled loan payments. According to RUS reports, about $10.5 billion of the $22.5 billion in G&T debt is owed by 13 financially stressed G&T borrowers. RUS defines financially stressed borrowers as those borrowers that have defaulted on their loans, had their loans restructured but continue to experience financial difficulties, declared bankruptcy, or formally requested financial assistance from RUS. Interest income is not recorded on delinquent debt until it is received.

Financially stressed borrowers' failure to make scheduled payments can have a significant impact on interest income. For example, one G&T borrower, Cajun Electric, has not been required to make interest payments on its $4.2 billion debt since filing for bankruptcy in December 1994. In addition, Cajun made total principal payments of only about $19 million from December 1994 through the end of fiscal year 1996. Based on Cajun's contractual interest rate of about 8.6 percent, RUS has forgone interest income of about $30 million per month, or about $1 million per day, since December 1994. In the meantime, the government continues to incur interest expense on financing related to this loan.

Interest Expense

The federal government's annual interest expense on funds provided for the RUS electric program is determined based on outstanding RUS borrowing from FFB, Treasury, and private lenders. Debt to FFB and Treasury totaled $27.5 billion (see table V.2) while debt to private lenders totaled about $2.7 billion for the fiscal year ending September 30, 1996.

Table V.2: Weighted Average Interest Expense for Fiscal Years 1992 Through 1996

Dollars in millions

	1992	1993	1994	1995	1996
Debt to FFB/Treasury	$27,881.9	$27,567.8	$27,387.0	$27,855.3	$27,484.6
Weighted average Treasury rate	.09505	.09323	.09229	.09134	.09012
Weighted average interest expense	**$2,650.2**	**$2,570.1**	**$2,527.5**	**$2,544.3**	**$2,476.9**

FFB debt on the electric program totaled $20.5 billion as of September 30, 1996. FFB obtains funds to make loans from Treasury. The RUS electric program also had a total of $7 billion in direct borrowing from Treasury at the end of fiscal year 1996. As shown in table V.2, to calculate the federal government's interest expense for RUS lending activities, we multiplied the total RUS debt owed to Treasury and FFB by the annual weighted average Treasury rate for each fiscal year.

To calculate interest expense for RUS debt with private lenders, we totaled the actual amounts paid to the lenders based on RUS audited financial statements and supporting documents. In conjunction with certain troubled debt restructuring, RUS assumed notes payable to private lenders for debt it previously guaranteed. A substantial portion of these balances is owed to the National Rural Utilities Cooperative Finance Corporation, a private lender to rural electric borrowers. The notes bear interest at rates ranging from 7.13 to 10.70 percent and mature through the year 2020.

Risk Assessment for the Rural Utilities Service Electric Portfolio

From fiscal year 1996 through July 31, 1997, the Rural Utilities Service (RUS) wrote off $1.5 billion in electric loans.[1] As of September 30, 1996, $10.5 billion of the $32.3 billion total electric portfolio represented loans to borrowers that are in bankruptcy or otherwise financially stressed. It is probable that the federal government will continue to incur substantial losses from loan write-offs relating to RUS borrowers that are currently bankrupt or financially stressed. It is also probable that future losses will arise from other RUS borrowers with high production costs and the inability to raise rates because of regulatory and/or market pressures.

The Federal Government's Financial Involvement

As of September 30, 1996, the RUS electric loan and loan guarantee portfolio totaled $32.3 billion. The bulk of the portfolio is made up of loans to the Generation and Transmission Cooperatives (G&Ts). The principal outstanding on these G&T loans is approximately $22.5 billion, about 70 percent of the RUS electric loan portfolio. Distribution borrowers make up the remaining 30 percent of the electric portfolio. Most of the RUS electric loans and loan guarantees were made during the late 1970s and early 1980s. For example, from fiscal years 1979 through 1983, RUS approved loans and loan guarantees of about $29 billion, whereas during fiscal years 1992 through 1996, it approved a total of about $4 billion in electric loans and loan guarantees. There are currently 55 G&T borrowers and 782 distribution borrowers. Our review focused on the G&T loans since they make up the majority, in terms of dollars, of the portfolio and generally pose the greatest risk of loss to the federal government. The federal government incurs financial losses when borrowers are unable to repay the balance owed on their loans and the government does not have sufficient legal recourse against the borrower to recover the full loan amount. In all instances, G&T loans are collateralized; however, RUS has never foreclosed on a loan. RUS generally has been unable to successfully pursue foreclosure once the borrower files for bankruptcy because the borrower's assets are protected until the proceedings are settled. In addition, in recent cases where debt was written off, the government forgave the debt and therefore will not attempt to pursue further collection.

Substantial Loan Write-offs Occurred in Recent Years

Under Department of Justice (DOJ) authority, RUS has recently written off a substantial dollar amount of loans to rural electric cooperatives. The total amount of debt written off between fiscal year 1992 and July 31, 1997, is about $1.5 billion. The most significant write-offs relate to two G&T loans.

[1]These write-offs were included in our analysis of net costs to the federal government in volume I.

In fiscal year 1996, one G&T made a lump sum payment of $237 million to RUS in exchange for RUS writing off and forgiving the remaining $982 million of its RUS loan balance. The G&T's financial problems began with its involvement as a minority-share owner in a nuclear project that experienced lengthy delays in construction as well as severe cost escalation. When construction of the plant began in 1976, its total cost was projected to be $430 million. However, according to the Congressional Research Service, the actual cost at completion in 1987 was $3.9 billion as measured in nominal terms (1987 dollars). These cost increases are due in part to changes in Nuclear Regulatory Commission (NRC) health and safety regulations after the Three Mile Island accident. The remaining portion is generally due to inflation over time and capitalization of interest during the delays. The borrower defaulted in 1986, had its debt restructured in 1993, and finally had its debt partially forgiven in September 1996. This borrower is no longer in the RUS program.

In the early part of fiscal year 1997, another G&T borrower made a lump sum payment of approximately $238.5 million in exchange for forgiveness of its remaining $502 million loan balance. The G&T and its six distribution cooperatives borrowed the $238.5 million from a private lender, the National Rural Utilities Cooperative Finance Corporation. The G&T had originally borrowed from RUS to build a two-unit coal-fired generating plant and to finance a coal mine that would supply fuel for the generating plant. The plant was built in anticipation of industrial development from the emerging shale oil industry. However, the growth in demand did not materialize, and there was no market for the power. Although the borrower had its debt restructured in 1989, it still experienced financial difficulties due to a depressed power market. RUS and DOJ decided that the best way to resolve the matter was to accept a partial lump sum payment on the debt rather than force the borrower into bankruptcy. The borrower and its member distribution cooperatives are no longer in the RUS program.

Additional Losses From Financially Stressed G&T Loans Are Probable in the Short Term

It is probable that RUS and DOJ will have additional loan write-offs and therefore that the federal government will incur further losses in the short term from loans to borrowers that have been identified as financially stressed by RUS management. Borrowers considered financially stressed have either defaulted on their loans, had their loans restructured but are still experiencing financial difficulty, declared bankruptcy, or have formally requested financial assistance from RUS. According to RUS reports, about $10.5 billion of the $22.5 billion in G&T debt is owed by 13 financially stressed G&T borrowers, as shown in table VI.1.[2] These borrowers are designated as A through M in table VI.1. At RUS' request, we only identified, by name, distressed borrowers that were in bankruptcy. Of these, four G&T borrowers are in bankruptcy with about $7 billion in outstanding debt. The remaining nine borrowers have investments in uneconomical generating plants and/or have formally requested financial assistance in the form of debt forgiveness from RUS.

Table VI.1: RUS Financially Stressed G&T Cooperatives, as of September 30, 1996

Dollars in millions

Borrower	Total debt outstanding
Borrower A[a,b]	$1,619.6
Borrower B	167.9
Borrower C	103.2
Borrower D[b]	562.3
Borrower E[b]	183.3
Borrower F[a,b]	1,101.2
Borrower G[a,b]	4,154.8
Borrower H[b]	313.4
Borrower I[b]	354.8
Borrower J	1,070.7
Borrower K	445.1
Borrower L	351.7
Borrower M[a]	92.8
Total debt	**$10,520.8**

[a]Cooperative in bankruptcy.

[b]State regulated cooperative.

As indicated above, much of the financially troubled borrowers' problems stem from their investments in nuclear-generating plants that were completed late and over budget or in coal-fired generating plants that were built to satisfy anticipated industrial growth that did not materialize. The investments in nuclear plants by RUS borrowers are for the most part minority interests in plants constructed by one or more investor-owned utilities (IOUs). According to RUS officials, among the reasons the plant

[2]In our previous report, Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio (GAO/RCED-97-82, April 11, 1997), we noted 12 G&T and distribution borrowers that were delinquent or in financial distress. However, in this report, we discuss 13 financially stressed G&T borrowers identified by RUS management. The primary difference is that this report does not include one financially stressed distribution borrower, but did include two borrowers that have officially requested financial assistance as discussed following table VI.1.

investments became uneconomical included rapidly increasing construction and material costs, changing NRC regulations, and soaring interest rates. Concurrent with these higher costs, projected demand for energy, in many cases, did not materialize. These investments resulted in high levels of debt and debt-servicing requirements, making power produced from these plants expensive. Since cooperatives are nonprofit organizations, there is little or no profit built into their rate structure, which helps keep electric rates as low as possible. However, the lack of retained profit generally means the cooperatives have little or no cash reserves to draw upon. Thus, when cash flow is insufficient to service debt, cooperatives must raise electricity rates and/or cut other costs enough to service debt obligations. If they are unable to do so, they may default on their government loans.

The following is a brief discussion of each of the 13 financially stressed G&T borrowers:

Borrower A: Invested in construction of a nuclear plant that experienced cost overruns and was never completed. The state commission denied rate increases to cover the cost of the cooperative's investment in the plant. The borrower defaulted on its loan in 1984 and declared bankruptcy in 1985. The bankruptcy proceedings have been in court for 12 years and are still not completely resolved.

Borrower B: Made an investment in a nuclear plant that proved to be uneconomical. While this borrower does not appear to be currently experiencing financial difficulties, RUS considers them financially stressed because they have formally requested financial assistance due to impending competitive pressures.

Borrower C: Made an investment in a nuclear plant that proved to be uneconomical. While this borrower does not appear to be currently experiencing financial difficulties, RUS considers them financially stressed because they have formally requested financial assistance due to impending competitive pressures.

Borrower D: Uses primarily coal-fired generation. The borrower overbuilt due to anticipated growth in electricity demand that did not occur. During construction of a new plant, economic conditions in the area changed and demand for electricity dropped, which resulted in less revenue than predicted from the plant. The cooperative was repeatedly denied rate increases to cover the cost of its plants by the state commission.

Borrower E: Has a small percentage share in a nuclear plant that proved to be uneconomical. The borrower has substantially higher electricity rates than the IOUs in its region. The cooperative has been denied rate increases to cover its losses by the state commission. Although the borrower has had some of its debt refinanced, it is still experiencing financial difficulties.

Borrower F: A G&T with primarily coal-fired generating plants that overbuilt due to anticipated industrial growth related to two large aluminum smelting companies. When aluminum prices dropped in the early 1980s, the companies threatened to move their operations if the cooperative did not lower electricity rates. The state commission denied rate increases over the fear of losing these industries. RUS restructured the borrower's debt in 1987 and 1990. The cooperative filed for bankruptcy in September 1996 because its other creditors were unwilling to negotiate.

Borrower G: Built a coal-fired plant and invested in a nuclear plant in the mid-1970s which was completed late and experienced construction cost overruns. Several factors contributed to the cooperative's heavy debt, including excess electricity generation construction resulting from overestimation of the demand for electricity during the 1980s. The new capacity was intended to serve a growth in demand that did not materialize. The state commission disapproved a rate increase and instead lowered rates to a level which precluded full debt service coverage. The commission also refused to support a restructuring agreement that included a significant RUS loan write-off.[3] The rate increase was requested by the cooperative because of its high costs. The borrower filed for bankruptcy in December 1994.

Borrower H: Invested in construction of a nuclear plant that proved to be uneconomical. The project was completed 10 years late and over budget. In addition, there was a dramatic drop in the demand for electricity in the cooperative's service area and the state commission would not allow rate increases to recover capital investment. The borrower had its debt restructured in 1987; however, it is requesting additional financial assistance due to anticipated competitive pressure. A final settlement between RUS and the borrower was reached in June 1997. The borrower will receive a write-off of $165 million. The final payment and related debt write-off will not occur until December 30, 1997.

[3]In states that regulate cooperatives, the state commission must approve restructuring agreements between the cooperative and its creditors.

Borrower I: Invested in a clean-burning coal plant that experienced severe cost overruns. The borrower has substantially higher electricity rates than the IOUs in its region. The state commission has denied the cooperative's request for rate increases. The borrower had some of its debt refinanced, but it is still experiencing financial difficulty.

Borrower J: Invested in a nuclear plant that proved to be uneconomical. The plant was completed late, which resulted in cost overruns. As a result, the cooperative's wholesale power rates are very high. The borrower has requested debt restructuring due to its high cost of production and anticipated competitive pressure.

Borrower K: Invested in a nuclear plant that proved to be uneconomical. The plant was completed late which resulted in severe cost overruns. The cooperative's wholesale power rates are very high, which has resulted in extreme unrest in the member distribution cooperatives. The borrower is surrounded by IOUs with lower wholesale rates. In addition, the borrower's system is very difficult and expensive to maintain and experiences frequent power outages. The borrower has requested financial assistance because of anticipated competitive pressure.

Borrower L: Invested in a nuclear plant that proved to be uneconomical. The plant was completed late, which resulted in severe cost overruns. The cooperative has only five member distribution cooperatives, which makes it difficult to cover its high production costs. This borrower chose not to declare bankruptcy and is seeking financial assistance. This borrower has refinanced its debt to lower its interest rate, but is still experiencing financial difficulty and has requested additional financial assistance.

Borrower M: Invested in a nuclear plant that proved to be uneconomical. In addition, the cooperative had a stagnant customer base in the 1980s. RUS tried to negotiate a restructuring agreement, but the state commission denied two separate plans. In April 1996, the borrower filed for bankruptcy.

In several instances noted above, state regulatory commissions denied the rate increases necessary for the G&Ts to cover their costs and service their RUS loans although several commissions had approved the projects prior to construction. Seven of the 13 financially stressed borrowers operate in states where regulatory commissions must approve rate increases. These commissions may deny a request for a rate increase if they believe such an increase will have a negative impact on the region.

According to RUS and DOJ officials, in the Wabash Valley bankruptcy case (borrower A), RUS recently received a legal decision which was unfavorable to its interests and may encourage additional requests for debt forgiveness from other RUS borrowers. In this case, the effect of the court's decision was to allow the borrower to repay only a portion of its RUS debt, even though RUS argued that such a ruling sets a precedent that may allow other cooperatives to avoid repaying their debts. RUS officials indicated that numerous borrowers, including all of the financially stressed borrowers, have already inquired about obtaining debt relief as a result of, among other things, the unfavorable legal decision. Although several of the financially stressed borrowers previously had their debts restructured, some are again in severe financial trouble.

Some Losses From Loans Currently Considered Viable Are Probable in the Future

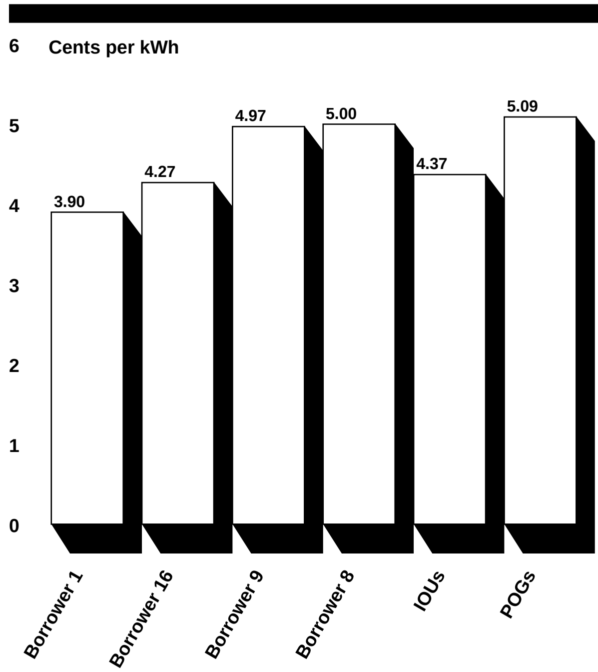
In addition to the financially stressed loans, RUS has loans outstanding to G&T borrowers that are currently considered viable by RUS but may become stressed in the future due to high costs and competitive or regulatory pressures. We believe it is probable that the federal government will eventually incur losses on some of these G&T loans.

We believe the future viability of these G&T loans will be determined based on their ability to be competitive in a deregulated market. In order to assess the ability of RUS cooperatives to withstand competitive pressures, we focused on the average revenue per kilowatthour (kWh) of 33 of the 55 G&T borrowers with loans outstanding of about $11.7 billion as of September 30, 1996. We excluded 9 G&Ts that only transmit electricity and the 13 financially stressed borrowers discussed above. Our analysis shows that for 27 of the 33 G&T borrowers, average revenue per kWh was higher in their respective North American Electric Reliability Council (NERC) regions[4] than IOUs and 17 of the 33 were higher than publicly-owned generating utilities (POGs), as shown in figures VI.1 to VI.8. These borrowers are designated as Borrowers 1 through 33 in figures VI.1 to VI.8. The number of borrowers adds to more than 33 because some overlap NERC regions and thus are shown more than once. The relatively high average production costs indicate that the majority of G&Ts may have difficulty competing in a deregulated market. RUS officials told us that several borrowers have already asked RUS to renegotiate or write off their debt because they do not expect to be competitive due to high costs. RUS officials stated that they will not write off debt solely to make borrowers more competitive.

[4] We used the 1995 NERC configuration because the latest available data on average revenue per kWh by NERC region were for 1995; NERC's configuration changed in 1996. See appendix III for a further discussion.

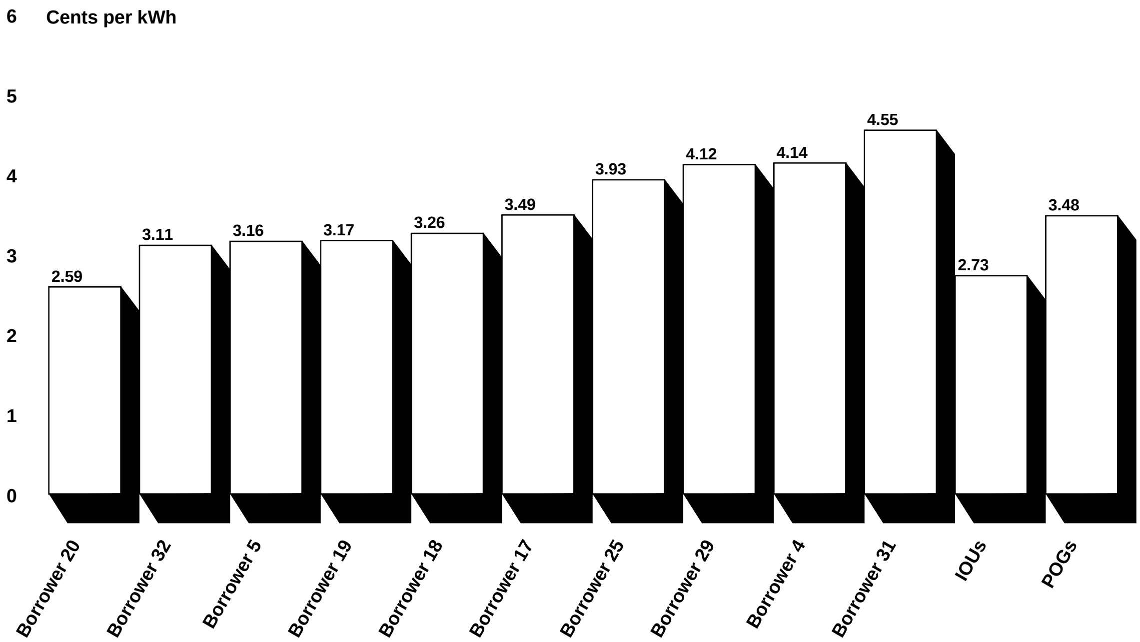
As with the financially stressed borrowers, some of the G&T borrowers currently considered viable have high debt costs because of investments in uneconomical plants. In addition, according to RUS officials, there are two unique factors that cause cost disparity between the G&Ts and IOUs. One factor is the sparser customer density per mile for cooperatives and the corresponding high cost of providing service to the rural areas. A second factor has been the inability to refinance higher cost Federal Financing Bank (FFB) debt when lower interest rates have prevailed. However, RUS officials said that recent legislative changes which enable cooperatives to refinance FFB debt with a penalty may help align G&T interest rates with those of the IOUs.

Figure VI.1: Average Revenue per kWh for G&Ts in the Southeastern Electric Reliability Council (SERC) Region



Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from the Energy Information Administration (EIA), and POG data from the American Public Power Association (APPA).

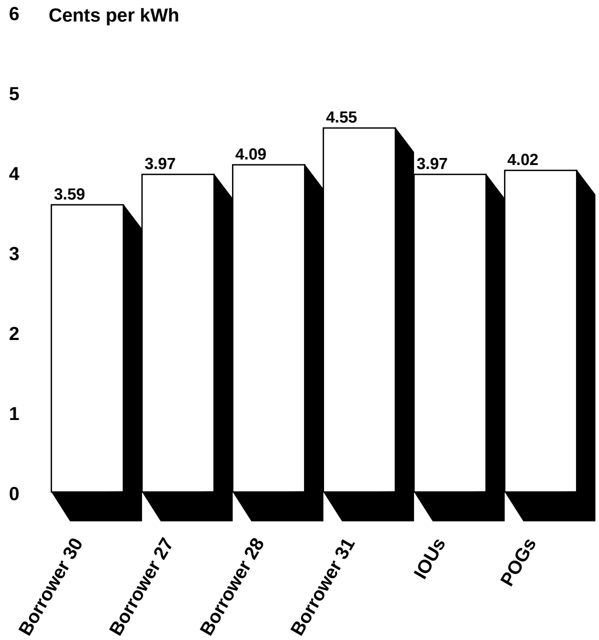
Figure VI.2: Average Revenue per kWh for G&Ts in the Southwest Power Pool (SPP) Region



Note: Borrower 31 serves both the Electric Reliability Council of Texas (ERCOT) and SPP regions.

Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

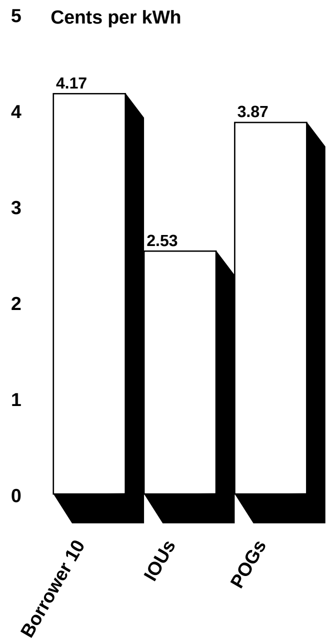
Figure VI.3: Average Revenue per kWh for G&Ts in the Electric Reliability Council of Texas (ERCOT) Region



Note: Borrower 31 serves both the ERCOT and SPP regions.

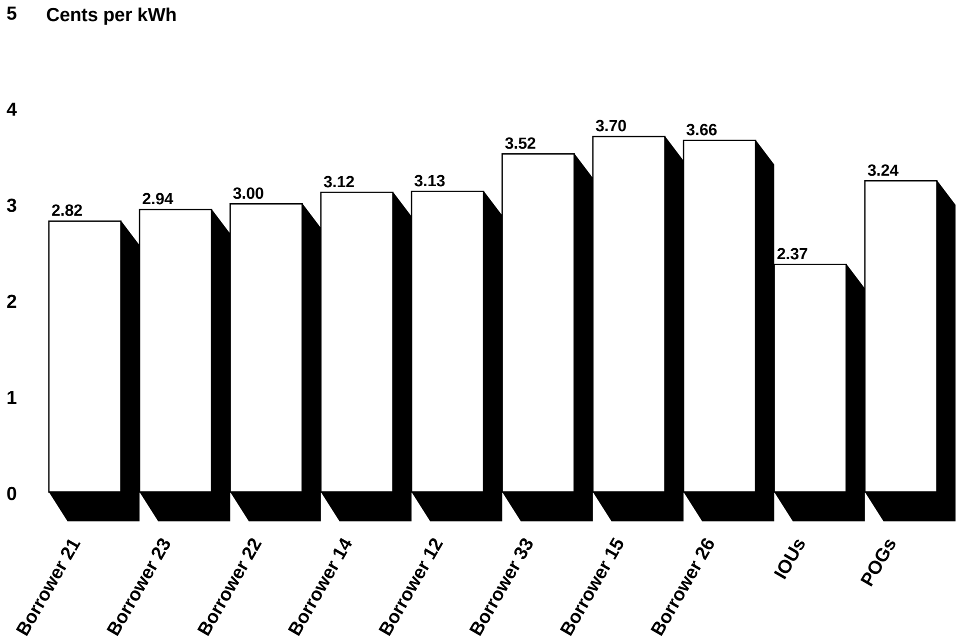
Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VI.4: Average Revenue per kWh for G&Ts in the Mid-America Interconnected Network (MAIN) Region



Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

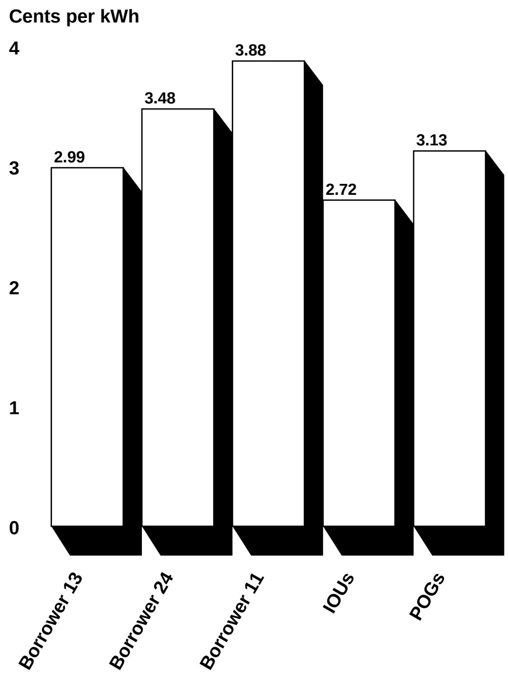
Figure VI.5: Average Revenue per kWh for G&Ts in the Mid-Continent Area Power Pool (MAPP) Region



Note: Borrower 26 serves both the WSCC and MAPP regions.

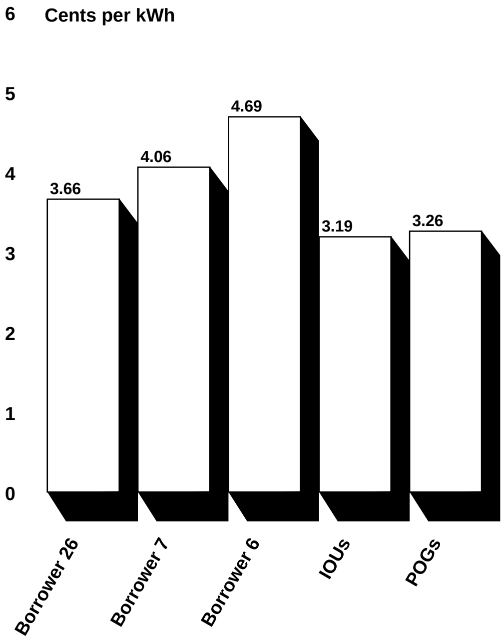
Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VI.6: Average Revenue per kWh for G&Ts in the East Central Area Reliability Coordination Agreement (ECAR) Region



Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

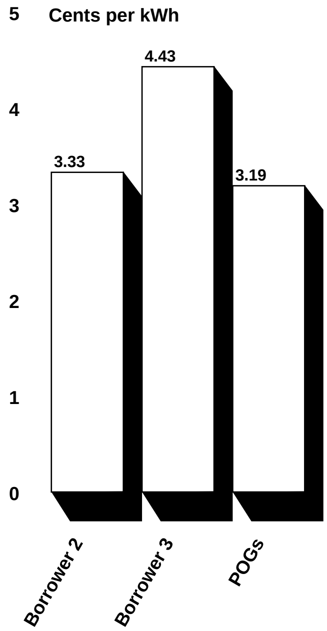
Figure VI.7: Average Revenue per kWh for G&Ts in the Western Systems Coordinating Council (WSCC) Region



Note: Borrower 26 serves both the WSCC and MAPP regions.

Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VI.8: Average Revenue per kWh for G&Ts in the Alaska Systems Coordinating Council (ASCC) Region



Note: Comparison includes POGs only; data for IOUs unavailable for ASCC.

Source: Developed by GAO based on data from RUS, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

In the short-term, G&Ts will likely be shielded from competition in the wholesale market because of the all-requirements wholesale power contracts between the G&Ts and their member distribution cooperatives. With rare exceptions, these long-term contracts obligate the distribution cooperatives to purchase all of their respective power needs from the G&T. In fact, RUS requires the terms of the contracts to be at least as long as the G&T loan repayment period. However, wholesale power contracts have been challenged recently in the courts by several distribution cooperatives because of the obligation to purchase expensive G&T power. According to RUS officials, one bankrupt G&T's member cooperatives are currently challenging their wholesale power contracts in court in order to obtain less expensive power. RUS officials believe that the long-term contracts will come under increased scrutiny and potential renegotiation or court challenges as other sources of less expensive power become available.

Wholesale rates under these contracts are currently set by a G&T's board of directors with approval from RUS. In states in which the public utility commissions regulate cooperatives, the borrower must file a request with the commission for a rate increase or decrease. Several of the currently bankrupt borrowers were denied requests for rate increases from state commissions. However, RUS officials indicated they do not expect G&Ts to pursue rate increases as a means to recover their costs because of the recognition of declining rates in a competitive environment. RUS officials also acknowledge that borrowers with high costs are likely to request debt forgiveness as a means to reduce costs in order to be competitive in the future.

Risk Assessment for Southeastern, Southwestern, and Western

The three power marketing administrations (PMAs)[1] have about $5.4 billion of appropriated debt, and Western has an additional $1.6 billion of irrigation debt and $165 million of nonfederal debt. The three PMAs market power that is substantially lower in cost than nonfederal utilities, which indicates that, in the current operating environment, they are competitively sound overall. However, all three PMAs have one or a few projects or rate-setting systems with problems that make risk of some loss to the federal government probable. The federal government, to varying degrees, is at risk of losing at least some of its investment in six projects/rate-setting systems: the Russell Project (Southeastern), Truman Project (Southwestern), Central Valley Project (Western), Pick-Sloan Program (Western), Mead-Phoenix Transmission Line (Western), and Washoe Project (Western).

The Federal Government's Financial Involvement

The federal government has substantial financial involvement in the activities of the three PMAs. As shown in table VII.1, the federal government's direct financial involvement, which consists of appropriated debt and irrigation debt, is more than $7 billion, and its indirect financial involvement, consisting of nonfederal debt at Western, is about $165 million.

Table VII.1: Federal Government's Financial Involvement in the Three PMAs as of September 30, 1996 or September 30, 1995

Dollars in millions

	Direct		Indirect	
PMA	Appropriated debt	Irrigation debt	Nonfederal debt	Total
Southeastern	$1,491[a]			$1,491
Southwestern	686[a]			686
Western	3,217	$1,635	$165	5,017
Total	**$5,394**	**$1,635**	**$165**	**$7,194**

[a]Because audited September 30, 1996, data were not available for Southeastern and Southwestern at the time of our fieldwork, we used September 30, 1995, appropriated debt balances for these two entities. According to the PMAs, these balances did not significantly change from 1995 to 1996.

[1]The three PMAs are Southeastern Power Administration, Southwestern Power Administration, and Western Area Power Administration.

Direct Financial Involvement

Appropriated debt consists of appropriations, which must be repaid with interest, primarily used to construct the generating and transmission facilities[2] related to the projects for which the three PMAs market power.

Western also is responsible for repaying irrigation-related construction costs on certain irrigation facilities, which we refer to as irrigation debt. Some project-specific authorizing legislation[3] provides for irrigation debt to be recovered primarily by power revenues. This irrigation debt is to be repaid without interest. Although irrigation debt is scheduled to be recovered with power revenues, Western does not view irrigation debt as a power cost. Therefore, when Western repays these amounts, neither the costs nor the related revenues will be in its financial statements. To the extent irrigation debt is repaid through electricity rates, Western's power customers are subsidizing irrigators.

For direct involvement, the federal government would have a financial loss if the PMAs were unable to repay principal or interest on debt owed to the federal government.

Indirect Financial Involvement

The federal government's indirect financial involvement, which consists of nonfederal debt related to certain projects marketed by Western, is about $165 million. The nonfederal debt is capital provided by Western's customers (primarily through the issuance of bonds) to finance capital improvement projects. The customers pay the debt service cost, and Western records the bond proceeds as a liability and records interest expense. Western then bills the customers for the production costs of electricity, including the debt service, and credits the customers for the debt service costs. Essentially, this arrangement results in customers directly paying for capital projects rather than paying for them indirectly through rates.

[2]Southeastern has no transmission facilities.

[3]Project-specific authorizing legislation determines how the costs of constructing reclamation projects are allocated and how repayment responsibilities are assigned among the projects' beneficiaries. Collectively, the federal reclamation statutes that are generally applicable to all projects and the statutes authorizing individual projects are referred to as reclamation law. In implementing reclamation law, the Bureau of Reclamation and Western are guided by implementing regulations, administrative decisions of the Secretary of the Interior and the Secretary of Energy, respectively, and applicable court cases. Reclamation law provides for Western to use its power revenues to repay Treasury a certain portion of the capital costs allocated to completed irrigation facilities that are determined by the Secretary of the Interior to be beyond the ability of the irrigators to repay (irrigation assistance).

For indirect involvement, the federal government would have a financial loss if it incurred unreimbursed costs in an effort to prevent Western from breaching agreements to service its nonfederal debt.

The Three PMAs Are Competitively Sound Overall

The three PMAS market power that is substantially lower in cost than power sold by nonfederal utilities, which indicates that they are currently competitively sound overall. The PMAS' low average revenue per kilowatthour (kWh)[4] are the result of their cost recovery structure,[5] other inherent cost advantages, and management actions to control costs. We also noted some disadvantages that the three PMAS experience because they are federal entities.

Average Revenue per kWh Has Been Substantially Lower Than Nonfederal Utilities

Overall, the three PMAS' average revenue per kWh were more than 40 percent below those of other nonfederal utilities for 1995. Moreover, GAO previously found[6] that the three PMAS' average revenue per kWh were consistently 40 percent or more below nonfederal utilities for the years 1990 through 1994. This indicates that the three PMAS, overall, are fairly well-positioned for an increased competitive environment resulting from deregulation. However, the three PMAS' competitive position could be eroded if they are required to recover additional power-related costs and/or if increased competition in the electric utility industry causes wholesale and retail electricity rates to significantly drop. Figure VII.1 illustrates the difference between the average revenue per kWh for these PMAS compared to investor-owned utilities (IOUS) and publicly-owned generating utilities (POGS) for 1995 in the primary North American Electric

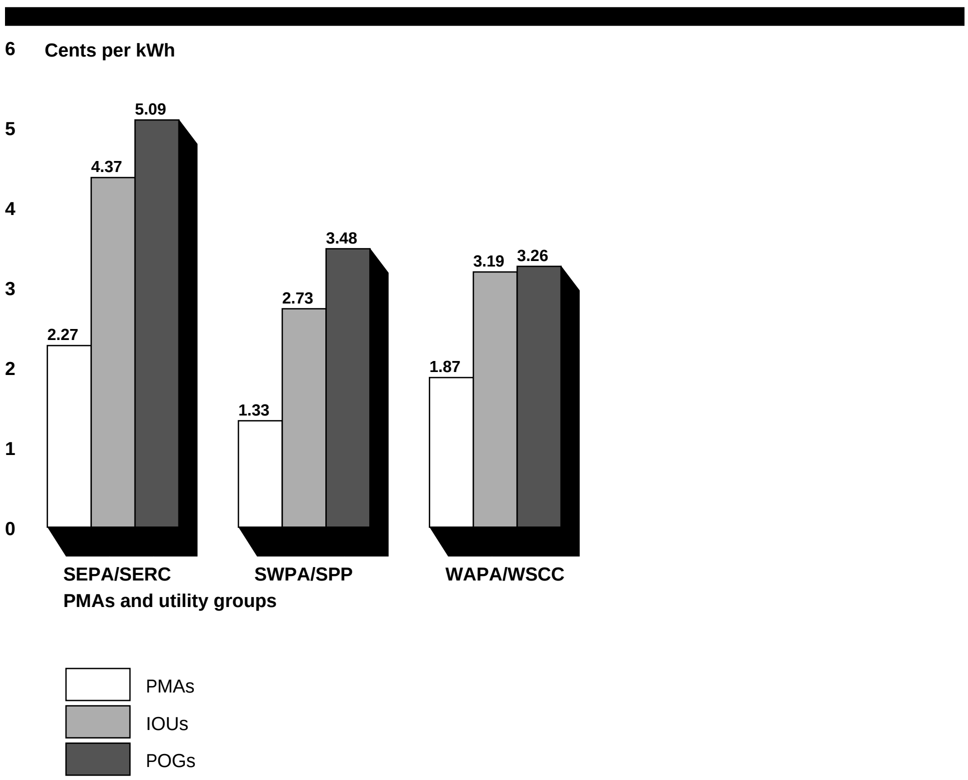
[4]See appendix III for a discussion of average revenue per kWh as an indicator of power production costs.

[5]Cost recovery structure refers to the three PMAs' ability to exclude certain costs from rates, called "unrecovered costs." Certain unrecovered costs may be recoverable in the future.

[6]Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, September 19, 1996).

Reliability Council (NERC) regions in which the PMAs operate.[7] See appendix III for a map of the NERC regions of the contiguous United States.

Figure VII.1: Average Revenue per kWh of Wholesale Power Sold, 1995



Legend

SEPA/SERC = Southeastern/Southeastern Electric Reliability Council
SWPA/SPP = Southwestern/Southwest Power Pool
WAPA/WSCC = Western/Western Systems Coordinating Council

Source: Developed by GAO based on data from the PMAs' 1995 annual reports, preliminary (unaudited) 1995 IOU data from the Energy Information Administration (EIA), and POG data from the American Public Power Association (APPA).

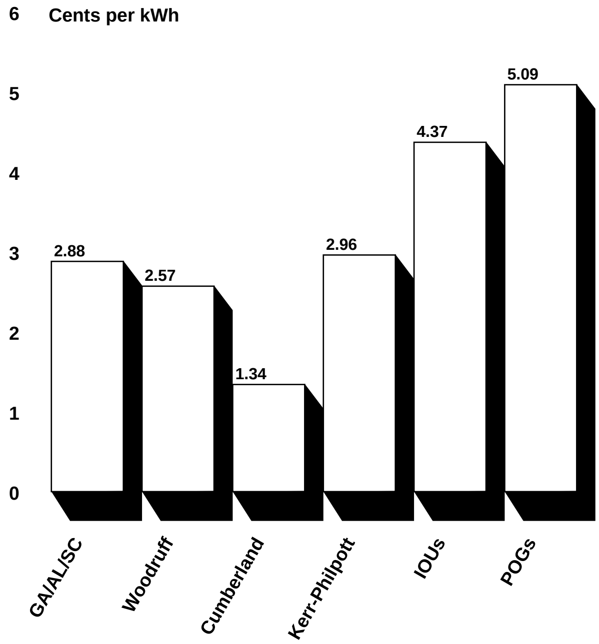
[7]The latest data available for all entities except Western were for 1995; Western had both 1995 and 1996 data. We used Western's 1995 data in order to ensure comparability to IOUs and POGs within the given time period. However, it should be noted that Western's overall average revenue per kWh decreased from 1.87 in 1995 to 1.65 in 1996. All of Western's projects' average revenue per kWh decreased in 1996 except Central Arizona (increased from 2.13 to 2.34), Washoe (increased from .99 to 1.02), and Falcon-Amistad (increased from 1.82 to 2.68); all three projects' average revenue per kWh were still more than 33 percent below IOUs and POGs in their respective regions. However, in the case of Washoe, average revenue per kWh may not be reflective of power production costs because not all costs are being recovered through rates. This also may be the situation at several other projects or rate-setting systems with financial problems discussed later in this appendix.

In addition to an overall assessment of the PMAS' costs, we compared the average revenue per kWh of each of the three PMAS' rate-setting systems[8] to IOUS and POGS in each system's geographic area. Except for a few rate-setting systems at Western and Southeastern, the three PMAS' average revenue per kWh by rate-setting system are about 40 to 50 percent below those of other nonfederal utilities for 1995. Figures VII.2 through VII.9 show a comparison of average revenue per kWh for each of the PMAS' 17 rate-setting systems to the relevant NERC region.[9] This detailed comparison is particularly relevant because PMA rates are set at a rate-setting system level. Some rate-setting systems market power in more than one NERC region and thus are shown in more than one figure.

[8]A rate-setting system consists of one or more power projects.

[9]We used the 1995 NERC configuration because the latest available data on average revenue per kWh by NERC region were for 1995. NERC's configuration changed in 1996. See appendix III for a further discussion.

Figure VII.2: Comparison of Average Revenue per kWh by Southeastern Rate-setting System for the SERC Region, 1995

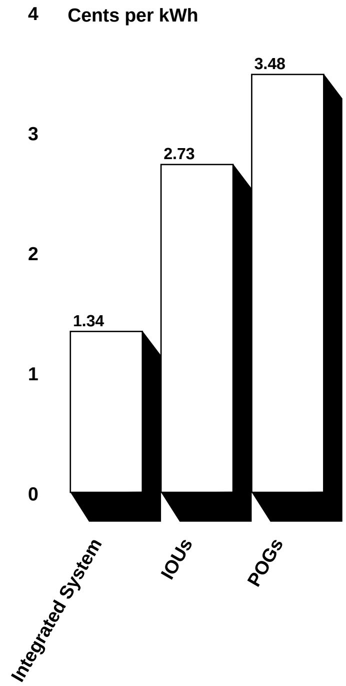


Legend

GA/AL/SC = Georgia/Alabama/South Carolina system.

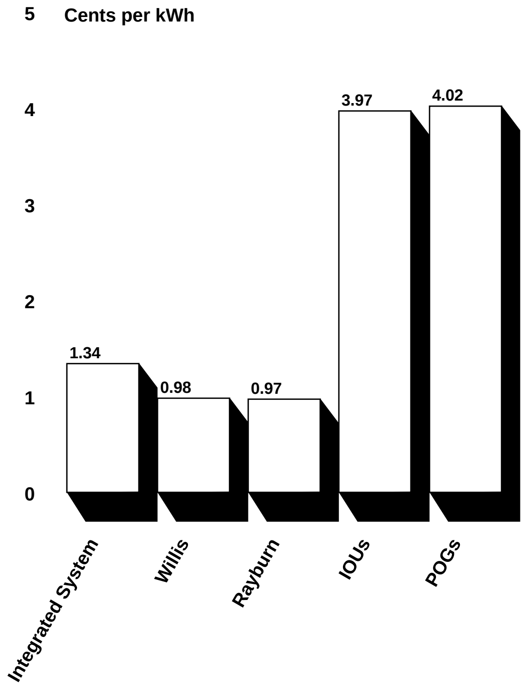
Source: Developed by GAO based on data from Southeastern's 1995 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VII.3: Comparison of Average Revenue per kWh by Southwestern Rate-setting System for the Southwest Power Pool (SPP) Region, 1995



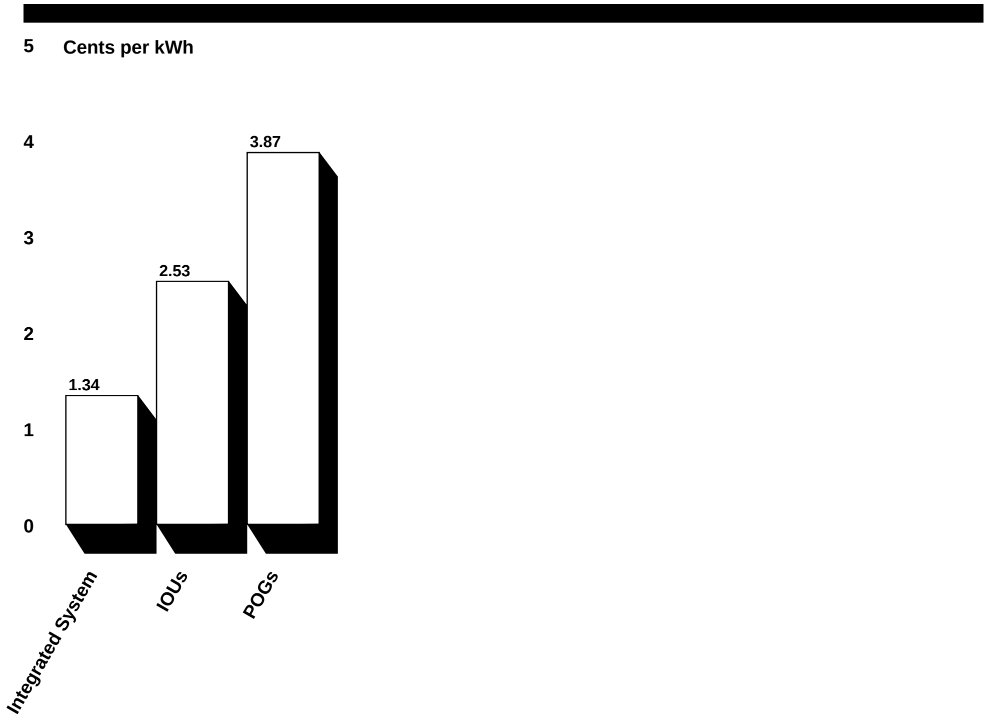
Source: Developed by GAO based on data from Southwestern's 1995 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VII.4: Comparison of Average Revenue per kWh by Southwestern Rate-setting System for the Electric Reliability Council of Texas (ERCOT) Region, 1995



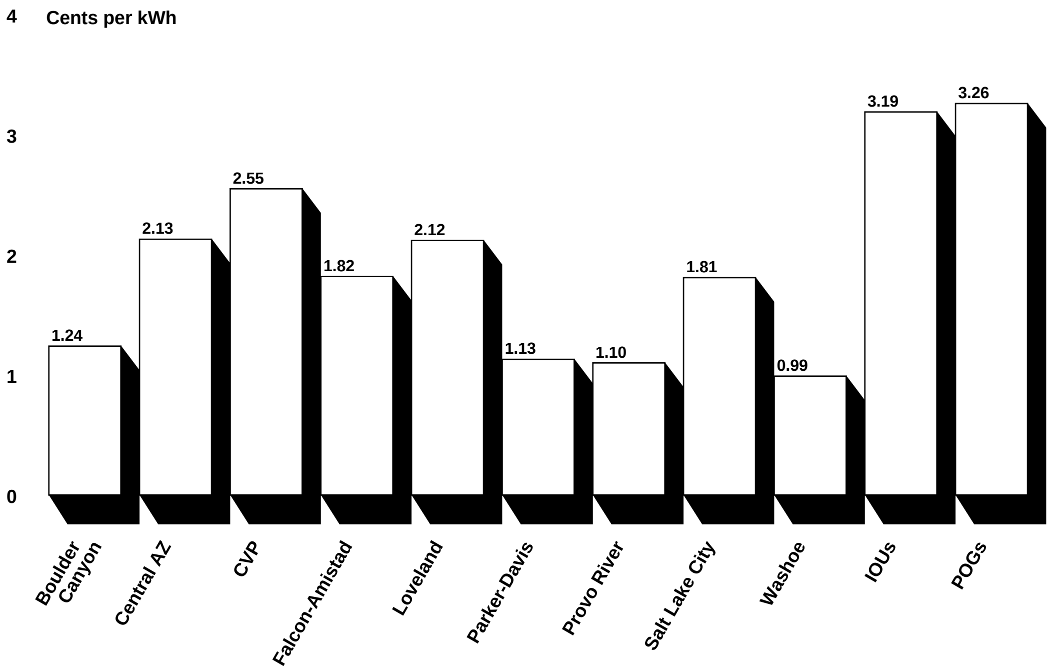
Source: Developed by GAO based on data from Southwestern’s 1995 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VII.5: Comparison of Average Revenue per kWh by Southwestern Rate-setting System for the Mid-Atlantic Interconnected Network (MAIN) Region, 1995



Source: Developed by GAO based on data from Southwestern's 1995 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

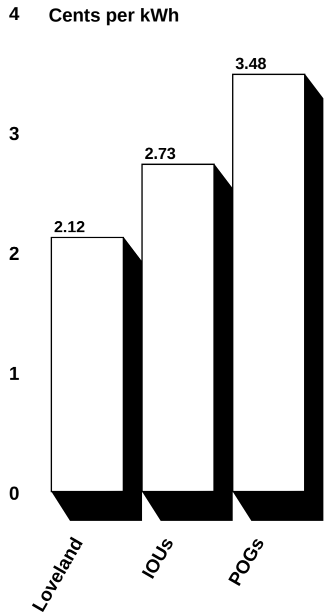
Figure VII.6: Comparison of Average Revenue per kWh by Western Rate-setting System for the Western Systems Coordinating Council (WSCC) Region, 1995



Note: As discussed later in this appendix, Western is planning to reduce rates for the Central Valley Project (CVP).

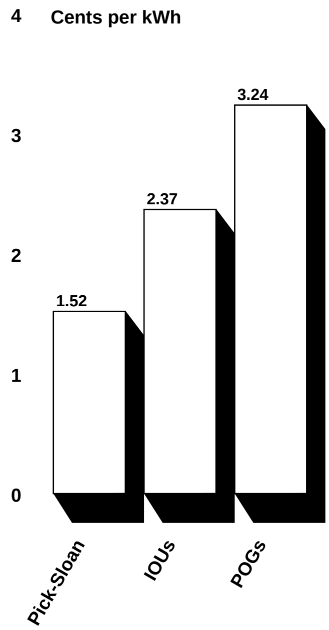
Source: Developed by GAO based on data from Western's 1995 annual report and appendix to the 1996 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VII.7: Comparison of Average Revenue per kWh by Western Rate-setting System for the SPP Region, 1995



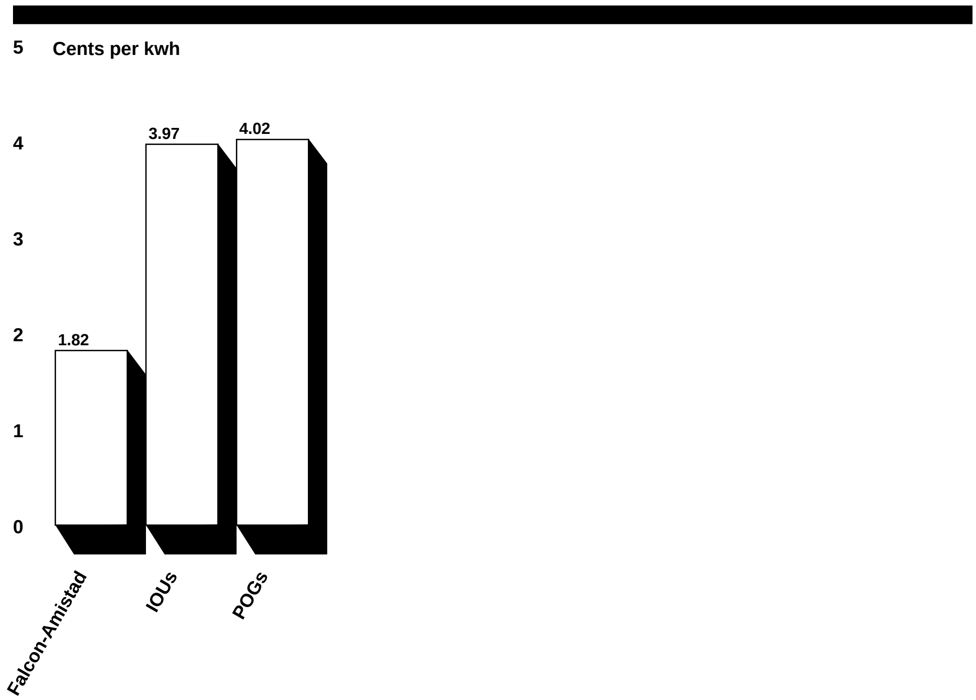
Source: Developed by GAO based on data from Western's 1995 annual report and appendix to the 1996 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VII.8: Comparison of Average Revenue per kWh by Western Rate-setting System for the Mid-Continent Area Power Pool (MAPP) Region, 1995



Source: Developed by GAO based on data from Western's 1995 annual report and appendix to the 1996 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Figure VII.9: Comparison of Average Revenue per kWh by Western Rate-setting System for the ERCOT Region, 1995



Source: Developed by GAO based on data from Western's 1995 annual report and appendix to the 1996 annual report, preliminary (unaudited) 1995 IOU data from EIA, and POG data from APPA.

Cost Recovery Structure and Inherent Advantages Contribute to Low-cost Power

As noted in volume 1 of this report and in our September 1996 report,[10] the three PMAs do not recover all costs associated with producing and marketing federal hydropower. These unrecovered costs include net financing costs, Civil Service Retirement System (CSRS) pension and postretirement health benefits, certain construction costs, power-related costs assigned to incomplete irrigation projects at Pick-Sloan, certain environmental costs legislatively precluded from recovery, and deferred operations and maintenance (O&M) and interest expenses. As we noted in volume 1 of this report, the PMAs are generally following applicable laws and regulations and believe that some of these costs, including construction and deferred O&M and interest expense, are recoverable through future rates. If the PMAs are required to recover some or all of the above unrecovered costs, which we estimate totaled about $185 million for

[10]Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, September 19, 1996).

fiscal year 1996, their ability to remain competitive may be impaired and the risk of future financial loss to the federal government increased.

The three PMAs have two other key inherent advantages that enhance their competitive positions. First, the three PMAs market power generated mainly by hydroelectric plants built decades ago, while other utilities are primarily dependent on coal and nuclear generating plants. Table VII.2 shows the contrast between the three PMAs and other utilities in the percentage of power coming from different generating sources.

Table VII.2: Percentage of Net Power Generation for the PMAs and Other Utilities, 1996

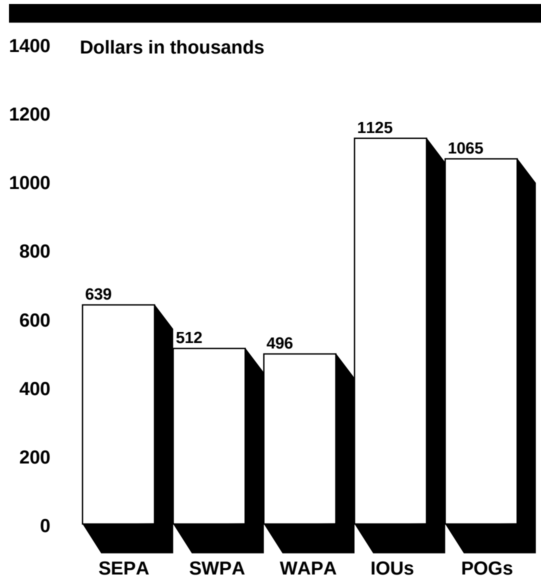
	Net power generated (percent)				
	Coal	Nuclear	Gas	Hydro	Other
Three PMAs	6.6[a]	0	0	93.4	0
Other utilities	57.5	24.2	9.7	6.1	2.5

[a]A relatively small amount of electricity marketed by Western is produced from coal-generating units.

Source: Energy Information Administration.

The hydroelectric plants that generate the power marketed by the PMAs have significant cost advantages over coal and nuclear generating plants. For example, the PMAs' hydroelectric plants, many of which were built 30 to 60 years ago, had relatively low construction costs. To show the relatively low capital cost of the hydropower plants, which contributes to the PMAs low average revenue per kWh, we compared the three PMAs' investment in utility plant per megawatt of capacity for these plants to those of other utilities. This ratio depicts the relative costs of building generating plants. As shown in figure VII.10, the three PMAs have substantially less invested in plant than the other utilities. Southeastern has substantially more invested in plant than the other two PMAs because the Russell Project has incurred capital costs of more than $500 million as of September 30, 1996, with no corresponding increase in generating capacity from the project's nonoperational portion.

Figure VII.10: Investment in Utility Plant per Megawatt of Generating Capacity, 1995



Source: Developed by GAO based on data from the PMAs' 1995 annual reports and 1995 POG and IOU data from EIA.

Compared to other utilities, the lower investment in PMA-related hydroelectric plants is partly the result of lower construction costs when these plants were built 30 to 60 years ago compared to more recent construction costs. Unlike the three PMAs and operating agencies, IOUs build new capacity to meet the future needs of customers. Many IOU and POG nuclear plants that were completed and are operating had significant capital construction costs, which are at least partly due to stringent Nuclear Regulatory Commission regulations. Utilities with coal plants must comply with the Clean Air Act, which requires significant investments in pollution control equipment for many plants. The PMAs' relatively low investment in utility plant results in a large cost advantage.[11] Appendix II describes the methodology used for computing the ratios in figure VII.10.

[11]Our analysis excluded nuclear plants that are mothballed and thus provide no capacity while resulting in significant capital costs. Mothballed nuclear plants can be either incomplete or completed plants that have had construction terminated or have been shut down either temporarily or permanently. Under generally accepted accounting principles, these costs are either written off or, if deemed allowable by the applicable regulator, are classified as "regulatory assets" and included in rates through amortization. Inclusion of these regulatory assets would have increased the POG and IOU investment.

Another major reason that hydroelectric plants result in lower power production costs is the cost of fuel. This is particularly important when comparing hydro plants to coal plants. The cost of coal is a major operating expense for most other utilities. Nuclear fuel is also a significant cost, although not nearly as large a factor as coal. In 1995, POGS' fuel costs represented about 11 percent of operating revenues, while IOUS' fuel costs represented about 16 percent of operating revenues. The PMAS, on the other hand, have the benefit of marketing power from hydroelectric plants, which do not have an associated fuel cost.[12]

The three PMAS' reliance on hydroelectric generation can also be a disadvantage in poor water years. Because of the reliance on water, the three PMAS' revenues can vary considerably and in some years are not sufficient to cover operating and interest expenses. As a result, the three PMAS are allowed to defer O&M and interest expense payments in years when revenue is not sufficient to cover these costs. Each of the three PMAS has at one time or another had to defer O&M and interest expense payments because of poor water conditions.[13]

Another key inherent advantage for the three PMAS is that, as federal agencies, they generally do not pay taxes. In contrast, IOUS do pay taxes. According to EIA, in 1995, IOUS paid taxes averaging about 14 percent of operating revenues. This average varies significantly from state to state due to differing state and local government tax laws. Taxes paid by IOUS include federal and state income taxes, real and personal property taxes, corporate franchise taxes, invested capital taxes, and municipal license taxes.

POGS, as publicly owned utilities, typically do not pay income taxes because they are units of state or local governments. However, many POGS do make payments in lieu of taxes to local governments. A study[14] of 670 POGS showed that POGS' median net payments and contributions as a percent of electric operating revenue for 1994 were 5.8 percent. With the exception of the Boulder Canyon Project, PMAS generally do not make payments in lieu of taxes to state or local governments. The Boulder Canyon Adjustment Act of 1940 requires annual payments to the states of

[12]As noted in table VII.2, a relatively small amount of electricity marketed by Western is produced from coal.

[13]The flexibility to defer O&M and interest expense enhances the three PMAs' ability to compete in a deregulated environment.

[14]1994 Payments and Contributions by Public Power Distribution Systems to States and Local Government, American Public Power Association, March 1996.

Arizona and Nevada. In 1995, $600,000, 1.2 percent of the project's operating revenue, was paid to these states in lieu of taxes.

Management Actions and the Nature of Customer Contracts Contribute to the Overall Sound Competitive Position of the Three PMAs

The three PMAS have taken action to enhance their ability to compete. However, because the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation (Bureau) operate federal projects, many capital and operating costs are beyond the control of the PMAS.

Southeastern, unlike Southwestern and Western, does not own any transmission lines and thus has only a small amount of controllable costs. The main cost under Southeastern's control is staffing, and management has held staffing at the PMA steady over the past few years.

At Southwestern, management recently reorganized and began to downsize staff to reduce costs. Southwestern management has also begun to benchmark leaders in the electric utility industry. This benchmarking effort is expected to help Southwestern identify ways to become more efficient and effective, reduce costs in the future, and identify appropriate performance measures that can be used to compare Southwestern's performance to its competition.

At Western, management has undertaken a substantial downsizing of staff and initiated other transformation efforts to prepare for competition. According to Western officials, Western is downsizing staff by about 25 percent and they expect this effort to result in annual savings of about $25 million. In addition, Western has redesigned jobs, instituted manager training, streamlined procedures, and continued to work on upgrading its financial management system to provide better business information. Western has also hired a benchmarking manager and formed a team to track its position relative to its competitors and to develop benchmarking techniques as part of its streamlining efforts.

The nature of the contracts with customers is also currently an advantage to the three PMAS. According to the PMAS, the contracts are cost-based, which means that if the PMAS' costs rise they have a mechanism to pass those costs along to customers. These long-term contracts, lasting up to 20 years, do not specify rates. Instead, the contracts specify that the customers will pay the rates in effect at the time. If the PMAS raise rates, the customers have the option of cancelling their contracts, generally within 1 year of a notice of a rate increase. These contracts are an advantage for the PMAS as long as their rates are below market because they can pass rising costs along to customers and still be competitive. However, should the three PMAS' rates get close to market rates, the customers' ability to cancel contracts could work to the three PMAS' disadvantage.

The PMAS also have certain disadvantages compared to nonfederal utilities that could impact their competitiveness. For example, Western is required to recover approximately $1.635 billion related to construction costs on completed irrigation facilities.[15] In addition, Western is required to recover through rates the cost of the Hoover Dam Visitor Center totaling an estimated $124 million.

Risk of Future Losses From Individual Rate-setting Systems/Projects Is Probable

Although the three PMAS are currently competitively sound overall, we identified situations at one or a few projects or rate-setting systems at each of the three PMAS that, taken as a whole, indicate that it is probable that the federal government will incur some future financial losses from one or more of the three PMAS' projects. The federal government, to varying degrees, is at risk of losing at least some of its investment in six projects/rate-setting systems: the Russell Project (Southeastern), Truman Project (Southwestern), CVP (Western), Pick-Sloan Program (Western), Mead-Phoenix Transmission Line (Western), and Washoe Project (Western). The issues related to each project, grouped by PMA, are discussed below.

Southeastern

To date, about one-half of the cost of constructing the Richard B. Russell Project[16] has been excluded from rates paid by power customers because the project has never operated as intended. In addition, interest associated with these capital costs is not paid to Treasury each year. Instead, interest—an estimated $29.9 million for fiscal year 1996—is capitalized and added to the construction work-in-progress (CWIP) balance annually. It is unclear whether the project will ever become fully operational. However, if the nonoperational portion of the project never operates as intended, it is probable that the federal government will not recover these construction and interest costs.

This project, located in the Savannah River between Georgia and South Carolina, is positioned between two existing dams and was built virtually

[15]Reclamation law provides for Western to repay certain portions of capital costs allocated to irrigation purposes which are determined to be beyond the ability of the irrigators to repay.

[16]The Richard B. Russell Project was originally named the Trotters Shoals Dam.

exclusively for the generation of hydropower. Under the Corps' tentative cost allocation, 99 percent of Russell's original construction costs and 93 percent of its annual O&M expenses are allocated to power. The project, which enjoyed broad support from electric utilities in North Carolina, South Carolina, and Georgia because of its potential to generate low cost power, was authorized by the Flood Control Act of 1966 and construction began in 1976.

The Russell Project has four operational conventional generating units that provide 300,000 kilowatts of capacity and four nonoperational pumping units intended to provide another 300,000 kilowatts of capacity.[17] The last of the four conventional units came on-line in 1986, and the costs associated with these units went into Southeastern's costs for recovery. However, because of litigation over excessive fish kills, the four pumping units that were completed in 1992 have never been allowed to operate commercially. As a result, the costs associated with them have been left in a CWIP account and have not been included in rates. Interest is not paid to Treasury each year on the federal government's investment in the nonoperational portion of the project; instead, it is capitalized and added to the CWIP balance. We estimate that the balance in the CWIP account was about $518 million at September 30, 1996. Since 1996 audited financial statements for Southeastern were not available at the time of our review, we estimated the September 30, 1996, figure by taking the CWIP balance at September 30, 1995—$488 million—and adding capitalized interest of $29.9 million, which we estimated based on the 6.125 percent interest rate applicable to the Russell Project.[18]

If the nonoperational portions of the Russell Project are allowed to operate commercially in the near future and the costs go into rates, Southeastern officials estimate that a rate increase of about 25 percent to customers of the Georgia-Alabama-South Carolina system would be necessary. This projected rate increase would be necessary for two reasons. First, interest expense related to the nonoperational units—which will be more than $30 million in fiscal year 1997—would be included in rates rather than capitalized. Second, the $518 million currently in CWIP would also be included in Southeastern's costs for recovery from power customers. This situation poses a challenge to

[17]The pumping units are designed to allow water, after it has passed through generating units, to be pumped back into the reservoir during periods of low demand for electricity. Then, the water can be used to produce power during periods of high demand for electricity.

[18]To estimate the net interest cost, we used the Russell Project interest rate of 6.125 rather than Southeastern's overall weighted average interest rate on outstanding appropriated debt of 4.4 percent for fiscal year 1995.

Southeastern in a competitive electricity market. According to a representative of the Southeastern Federal Power Customers, a customer group that represents most of Southeastern's customers, power from the Georgia-Alabama-South Carolina system would remain competitive even after a 25 percent rate increase. The customer group's view, combined with the current production cost advantage[19] of the Georgia-Alabama-South Carolina system, of which Russell is a part, indicate that the system should be able to remain competitive if the nonoperational pumping units are allowed to operate commercially and costs are put into rates in the near future. Under this scenario, we believe the risk of loss to the federal government is remote. However, the longer the eventual operation of the Russell project is delayed, the greater the costs that will have to be recovered through rates and the greater the potential impact on rates. If full deployment of the nonoperational units continues to be delayed, at some point the price of the power may not be competitive. We believe this poses a reasonably possible risk of future loss to the federal government.

Litigation over the Russell Project is still pending. Southeastern's management believes that the Russell Project is still viable and that the litigation will be settled by allowing the project to operate commercially. However, under current policy guidance, if the nonoperational units at Russell are not allowed to be put into commercial service, the power customers will not be required to repay this large federal investment.[20] We believe that under this scenario, it is probable that the federal government will lose its entire $518 million investment.[21]

Southwestern

A situation similar to Russell exists at the Harry S. Truman Dam and Reservoir, which is located in the Osage River in Missouri.[22] Designed originally for flood control, hydropower and recreation were later added as authorized project purposes. Construction of the Truman project began in October 1964 and it was placed in service (for flood control and

[19]As shown in figure VII.2, the Georgia-Alabama-South Carolina system's average revenue per kWh for 1995 was 2.88 cents per kWh, compared to 4.37 cents and 5.09 cents for IOUs and POGs, respectively, in the SERC region.

[20]This refers to policy guidance contained in Department of Energy (DOE) order RA6120.2 through which the recovery of power-related costs has been implemented by the Secretary of Energy.

[21]This $518 million at risk represents about 35 percent of the federal government's financial involvement of $1,491 million at Southeastern.

[22]The Harry S. Truman Project was originally named the Kaysinger Bluff Dam and Reservoir. Public Law 92-267 changed the name of the project to the Harry S. Truman Dam and Reservoir on May 26, 1970.

recreation) in November 1979. The in-service dates for hydropower generating units range from January 1980 to September 1982.

The Truman Project has six generating units that could provide 160,000 kilowatts of capacity and are also designed to operate as pumping units. However, because of design problems and fish kills caused by the pumping units, the Truman project has never been operated at its 160,000 kilowatt capacity. Instead, only 53,300 kilowatts have been declared to be in commercial operation and use of the pump-back facilities has never been commercially implemented. As a result, the Corps determined that it would be inappropriate to recover through power rates the costs associated with the units that have not been used commercially.

The Corps prepared an interim cost allocation for this project which accounted for the Truman Project not being fully operational. Southwestern petitioned the Federal Energy Regulatory Commission (FERC) to have the cost of the nonproducing portion of the assets deferred from inclusion in power rates until the project becomes fully operational. FERC concurred as part of its approval of Southwestern's 1989 power rates. As a result of FERC's decision, Southwestern has deferred the inclusion of the estimated amount of the costs associated with the nonoperational units in Southwestern's reimbursable share of the project's costs. Thus, $31 million has been deferred from recovery through power rates, reducing the total to be repaid from $158 million to $127 million.[23] This deferral is accomplished through an adjustment to Southwestern's appropriated debt each year. According to Southwestern officials, the $31 million adjustment is not a permanent elimination of these costs from Southwestern's appropriated debt; these costs will be included in rates and recovered from power customers if the Harry S. Truman facility operates as designed. Corps officials also told us that the Corps is making progress in addressing the design problems. The Corps has modified four of the Truman units and expects to complete modifications to the other two units by about mid-January, 1998. According to Corps officials, the modification program should increase Truman's unit availability. However, the issue of fish kills caused by the pumping units has not been resolved and associated capacity has not been restored. In contrast to the situation at Russell, where interest is capitalized on the CWIP balance and not paid to Treasury annually, Southwestern has paid interest on the $31 million deferral through fiscal year 1996.

[23]According to Southwestern officials, the deferral does not affect O&M costs since all power-related O&M expenses are paid annually.

Unless there is a change in the status of the pump-back units, which we believe is unlikely given the time frame they have been inoperable, it is probable that the federal government will lose the $31 million[24] that has been deferred from rates. However, if the pump-back units are allowed into commercial operation and placed into rates, we believe that Southwestern's relative cost advantage[25] indicates that it could absorb the $31 million deferral without a significant impact on rates. Additionally, since Southwestern pays annual interest on the deferred Truman costs, the risk is not increasing over time due to an increasing balance that would have to be repaid if the units become operational in the future. If the units do become operational, we believe the risk of future losses to the federal government is remote.

Western

Central Valley Project

The Central Valley Project (CVP), which had outstanding appropriated debt of about $267 million as of September 30, 1996, and incurred a $24 million loss in fiscal year 1996,[26] faces competition in the California market from low-cost producers and others selling surplus power. Western officials, who market CVP power, have responded to this competition by cutting rates by about 26 percent in fiscal year 1996 and establishing a plan to further reduce rates for CVP power by exercising escape clauses in contracts to purchase power for resale to CVP customers.[27] According to Western officials, the power they are currently purchasing is priced higher than CVP's actual production costs, and eliminating the power purchases will enable them to reduce CVP's rates and be competitive. Western officials said that they have studied the CVP purchase power contracts, determined when they can exercise the escape clauses, and assessed the resulting rate reductions that can be implemented over the next few years. The officials said they were confident that CVP can price its power

[24]This $31 million at risk represents about 5 percent of the federal government's financial involvement of $686 million at Southwestern.

[25]As shown in figure VII.3, the Integrated System's (of which Truman is a part) average revenue per kWh for 1995 was 1.34 cents per kWh, compared to 2.73 cents and 3.48 cents for IOUs and POGs, respectively, in the SPP region.

[26]The $24 million net loss is an accrual-based net loss; CVP was able to meet its cash flow requirements in fiscal year 1996.

[27]According to Western officials, CVP is currently in a formal rate-making process for a rate reduction effective October 1, 1997, that will reduce the CVP rate to 2.06 cents per kWh. Western officials state that further reductions are planned in fiscal year 1999 to 1.96 cents per kWh and in fiscal year 2001 to 1.86 cents per kWh.

competitively by eliminating the contracts to purchase relatively expensive power.

A representative of a group of CVP customers confirmed that CVP power is presently priced above market and agreed with the Western officials' assessment that by eliminating the contracts to purchase power CVP can price its power competitively. The representative noted that no customers have cancelled contracts with CVP because they believe that the current competitive difficulties can be resolved. However, he also said that the customers that he represents would prefer that Western officials in the future focus on merely selling CVP's output rather than on entering into contracts to purchase power in an effort to meet customers' demand for power.

Whether Western management's efforts to increase CVP's competitiveness will be successful is uncertain. Moreover, the implementation of the Central Valley Project Improvement Act (CVPIA) of 1992 is likely to impact the availability of water for power generation. CVPIA strengthened existing fish and wildlife project purposes by adding fish and wildlife mitigation, protection, and restoration as an authorized purpose of CVP. This legislation emphasized the safeguarding of fish and wildlife. As a result, less water may be available for irrigation, power generation, municipal and industrial use, and other purposes. To the extent that power revenues are reduced as a result of the implementation of CVPIA, the uncertainty over the repayment of the federal government's investment in hydropower facilities at CVP increases. In addition, according to Western officials, when the reallocation of the water occurs, there will be a reallocation of substantial costs to power. Reallocating costs to power when power revenues are expected to be reduced would further increase the uncertainty surrounding the repayment of the federal government's investment in hydropower facilities at CVP.

Moreover, the amount of water available for hydropower production at CVP may be further reduced as a result of changes in the flow of water from the Trinity River. The 1984 Trinity River Basin Fish and Wildlife Management Act provided for a program to restore fish and wildlife populations to levels that existed just prior to the construction of the Trinity River and Lewiston dams in Western's Trinity River Division in 1963, which diverted a large portion of the Trinity River's water to the Central Valley of California. We believe, and PMA officials have agreed, that the changes in the Trinity River water flow resulting from the restoration program may increase the risk of loss to the federal government from CVP. These uncertainties, combined with the competition CVP faces, lead us to believe that it is reasonably possible that the federal government will lose some of its $267 million investment[28] in CVP.

Pick-Sloan Missouri Basin Program

The Pick-Sloan Missouri Basin Program (Pick-Sloan) is a comprehensive plan to manage the water and hydropower resources of the Missouri River Basin.[29] Substantial capital costs for Pick-Sloan hydropower facilities and water storage reservoirs have been allocated to authorized irrigation facilities that are incomplete and infeasible. Western is currently using water to generate power that would have been used by irrigators if the irrigation projects had been completed. If the costs had been allocated based on actual use, they would have been allocated primarily to power and recovered through power rates within 50 years, with interest. However, as long as the costs are allocated to incomplete or infeasible irrigation projects, they will likely never be recovered. Since all but one of the irrigation facilities are not expected to be completed, the capital costs assigned to the others will not be repaid unless the Congress approves a change in the cost allocation methodology used to distribute costs to the various program purposes or deauthorizes the incomplete or infeasible irrigation facilities.[30] In May 1996,[31] we estimated that these capital costs were about $454 million as of September 30, 1994. Since these costs increased by an average of nearly $5 million annually between fiscal year 1987 and fiscal year 1994, we estimate that the costs totaled about $464 million as of September 30, 1996. Under the current repayment criteria, it is probable that Western will not be required to recover the principal or any interest on the $464 million[32] investment.

Mead-Phoenix Transmission Line

Another project with questionable financial viability is the Mead-Phoenix Transmission Line. Mead-Phoenix was recently added to the Pacific Northwest-Pacific Southwest Intertie (Transmission) Project intended to

[28]This $267 million at risk represents about 5 percent of the federal government's financial involvement of $5,017 million at Western.

[29]Pick-Sloan encompasses those parts of Colorado, Iowa, Kansas, Minnesota, Missouri, Montana, Nebraska, North Dakota, South Dakota, and Wyoming from which water drains into the Missouri River.

[30]Any changes made regarding the program's power and irrigation purposes may necessitate reviewing other aspects of the agreements—specifically, the agreements involving areas that accepted permanent flooding from dams in anticipation of the construction of irrigation projects that are now not likely to be constructed.

[31]Federal Power: Recovery of Federal Investment in Hydropower Facilities in the Pick-Sloan Program (GAO/T-RCED-96-142, May 2, 1996).

[32]This $464 million at risk represents about 9 percent of the federal government's financial involvement of $5,017 million at Western.

increase power transmission capability between central Arizona, southern Nevada, and southern California. This transmission project was a joint venture between Western and 15 other utilities and began operation in April 1996. Western's share of the total project's costs is about 34 percent. Western's portion of the cost of the project, including capitalized interest, is about $94.7 million. Western officials said that, in 1990 and 1993, prospective customers of the Mead-Phoenix line indicated that their demand for power from the line significantly exceeded Western's share of capacity. However, anticipated demand for power from the line later dropped precipitously and it is unclear whether Western will be able to successfully market its entire transmission capacity.

In March 1996 and again in September 1996 testimony before the Subcommittee on Water and Power Resources, House Committee on Resources,[33] Western officials said that they were aggressively marketing the remainder of the line's capacity. The Western officials indicated that if the project does not achieve the level of sales assumed in developing the transmission charges, they will initiate a new rate process to assure recovery of project costs. Western officials said that they were considering blending the Mead-Phoenix Transmission Line's rates into the overall rates of the Pacific Northwest-Pacific Southwest Intertie Project, of which it is a part. The Western officials asserted that doing this would make the Mead-Phoenix costs recoverable and that they had successfully done similar types of consolidations in the past. However, to date, the financial results have been discouraging. From April 1996, when it was placed in service, through January 1997, Mead-Phoenix has generated revenues of only about $71,319 while incurring O&M and interest expenses of nearly $7.3 million, resulting in a net loss of about $7.2 million. The transmission line's poor financial performance raises serious questions about its financial viability. If the consolidation under consideration cannot be successfully implemented, we believe it is probable that the federal government will lose at least some of its $94.7 million[34] investment in Mead-Phoenix. Even if the consolidation can be completed, there is no indication that the demand for power from the line will increase or that Western will be able to successfully market its entire transmission

[33]Western Area Power Administration (WAPA) Construction and Maintenance Activities and Bureau of Reclamation Power Facilities Management, Hearing Before the Subcommittee on Water and Power Resources, House Committee on Resources, 104th Cong., 2nd Sess. (March 19, 1996), and Statement of Mr. J. M. Shafer, Administrator, Western Area Power Administration, United States Department of Energy, Hearing Before the Subcommittee on Water and Power Resources, House Committee on Resources, 104th Cong., 2nd Sess. (September 19, 1996).

[34]This $94.7 million at risk represents about 2 percent of the federal government's financial involvement of $5,017 million at Western.

capacity, resulting in a reasonably possible risk of future loss to the federal government.

Washoe Project

The Washoe Project (Stampede Powerplant), located in west-central Nevada and east-central California, is not generating sufficient revenue to cover annual power-related operating expenses and interest or to repay the federal investment. In fact, all required payments of annual operating expenses and interest charges have not been made to Treasury since the project came on line in 1988, with the deferred payments totalling about $4.1 million at the end of fiscal year 1996. In addition to the deferred annual expenses and interest payments, the Washoe Project had $8.9 million of appropriated debt at September 30, 1996.

In January 1997, Western projected that Washoe would have to sell its power at a rate of at least 5.7 cents per kWh to cover annual operating expenses (excluding depreciation), interest charges, and debt repayments. This projection is substantially different from the Western officials' January 1996 projection that Washoe power would have to be sold at a rate of at least 11 cents per kWh to cover these costs. Both projections are substantially higher than the Washoe average revenue per kWh of energy sales of 1.02 cents in fiscal year 1996. The change in projection by Western is due to the reallocation of some Washoe costs from power to fish hatcheries protection which, according to Western officials, does not require recovery through rates from power customers. We believe that the costs reallocated are still power-related costs and remain a net cost to the federal government. As with the Mead-Phoenix Transmission Line, Western officials said that they were considering combining the Washoe Project power with the Central Valley Project and establishing a blended rate that would recover all costs associated with both projects, noting that they had successfully carried out similar types of consolidations in the past. However, CVP is itself a problem project, which would make the risk to the federal government from Washoe reasonably possible even after a consolidation.

We concur with Western, which stated in its 1995 annual report that it is unlikely that Washoe will be able to generate sufficient revenues to repay the federal investment. Moreover, we believe that as a stand-alone rate-setting system, Washoe will continue to incur annual operating losses and it is probable that the federal government will not recover the $13 million[35] of appropriated debt and deferred payments.

[35]This $13 million at risk represents about 0.3 percent of the federal government's financial involvement of $5,017 million at Western.

Risk Assessment for the Bonneville Power Administration

The Bonneville Power Administration (BPA) had over $17 billion of debt and about $766 million of interest expense as of and for the year ended September 30, 1996. These high fixed costs limited BPA's flexibility to lower rates and significantly contributed to BPA's loss of sales to its preference and industrial customers in recent years. However, as a result of existing customer contracts, a memorandum of agreement (MOA) limiting fish and wildlife mitigation costs, and currently large financial reserves, we believe that the risk of any significant loss to the federal government from BPA is remote through fiscal year 2001. After fiscal year 2001, we believe that expiration of customer contracts, significant risks from market uncertainties, BPA's high fixed costs, and substantial upward pressure on other expenses make the risk of loss to the federal government reasonably possible. This risk will begin to decline after fiscal year 2012, all else being equal, if BPA pays off its nonfederal debt as scheduled. One small project that would have served BPA, Teton Dam, represents a probable financial loss to the federal government.

The Federal Government's Financial Involvement

The federal government has substantial direct and indirect financial involvement in the activities of BPA. The direct involvement relates to BPA's appropriated debt, Treasury bonds, and irrigation debt.[1] For all three categories of direct debt, BPA is repaying the federal government. The federal government's indirect financial involvement relates to what BPA calls its nonfederal project debt ("nonfederal debt"),[2] which is due primarily to construction of nuclear projects of the Washington Public Power Supply System. Table VIII.1 details the amounts of direct and indirect debt by type.

[1]Aid to Irrigation (which we refer to as irrigation debt) is the legal obligation to repay costs incurred to construct federal irrigation projects that are determined by law to be beyond the irrigators' ability to repay.

[2]BPA used its contracting authority to acquire all or part of the generating capability of power projects of the Washington Public Power Supply System, a municipal corporation of the state of Washington. Under these agreements, BPA contracts to pay all or part of the annual project budgets, including debt service, whether or not the projects are completed. BPA does not have the authority to borrow from nonfederal sources or to construct power generating facilities.

Table VIII.1: The Federal Government's Financial Involvement in BPA as of September 30, 1996

Dollars in billions

	Financial involvement		
Description	**Direct**	**Indirect**	**Total**
Appropriated debt	$6.8		**$6.8**
Treasury bonds	2.5		**2.5**
Irrigation debt	0.8		**0.8**
Nonfederal debt		$7.1	**7.1**
Total	**$10.1**	**$7.1**	**$17.2**

Direct Financial Involvement

BPA's appropriated debt consists of appropriations primarily used to construct the generating and transmission projects from which BPA markets power. The total of $6.85 billion of appropriated debt as of September 30, 1996, carried a weighted-average interest rate of about 3.5 percent. Retroactively effective to the first day of fiscal year 1997, the Omnibus Consolidated Rescissions and Appropriations Act of 1996 authorizes the restructuring of this debt, reducing the principal to an estimated $4.29 billion and increasing the associated interest rate to approximately 7.1 percent. According to BPA's 1996 final rate proposal, the transaction "is intended to permanently eliminate subsidy criticisms directed at the relatively low interest rates assigned to historic Federal Columbia River Power System appropriations."[3] The dates when this debt is due, which extend through fiscal year 2046 and average about 26 years remaining, are not changed by the legislation.

According to BPA, the legislated restructuring is such that the present value of the new (revised) appropriated principal is equal to the present value of the principal and interest payments scheduled before the restructuring, plus $100 million. The $100 million is spread pro rata among all outstanding appropriations and results in an increase of $100 million in present value terms on related debt service payments. The resulting new principal amounts are assigned interest rates based on prevailing Treasury yield curve interest rates at the time of the transaction. With the exception of the additional $100 million and the interest on it, we believe that in substance this transaction does not change the government's future net

[3]BPA is part of the Federal Columbia River Power System (FCRPS), which also includes the power-related operations of the Corps and the Bureau. BPA is responsible for marketing power from FCRPS.

financing cost[4] and, even if implemented in fiscal year 1996, would not have changed the $377 million estimated net financing cost on BPA appropriated debt for fiscal year 1996.

Beginning in fiscal year 1997, all BPA's appropriations are required by law to be assigned prevailing Treasury yield curve interest rates. The Refinancing Act also requires that BPA's Administrator offer to include in all future and existing contracts for the sale of electric power, transmission, or related services terms that ensure that ratepayers pay no more principal and interest on the restructured appropriations than the act prescribes.

BPA also had about $2.5 billion of medium- and long-term debt held by Treasury in the form of BPA bonds. BPA's Treasury bond borrowing stems from authority granted in the Federal Columbia River Transmission System Act of 1974, as amended, that allows BPA to borrow up to $3.75 billion directly from Treasury. The $3.75 billion consists of two separate borrowing authority limits: $1.25 billion for conservation and renewable energy investments and $2.5 billion for transmission and other capital investments.[5]

In borrowing these funds, BPA sells bonds to Treasury at interest rates set by Treasury. Interest rates are determined based on comparable debt with similar terms issued by U.S. government corporations. The rates are adjusted to reflect the cost of specific features of BPA's bonds, such as the maturity date and the ability to call the bonds. The weighted-average interest rate on this debt as of September 30, 1996, was about 7.5 percent. The 7.5 percent interest rate results from the combination of BPA refinancing its Treasury bonds and/or retiring these bonds prior to their maturity. BPA paid a call premium on this refinancing that was established by Treasury prior to issuance of the bonds.

In addition to appropriated debt and Treasury bonds, BPA is responsible for repaying irrigation-related construction costs on certain Bureau of Reclamation irrigation facilities, as provided by project-specific

[4]However, if BPA repays the principal before it is due, and the federal government's cost of money has declined, the federal government will experience a decrease in cash flow and a resulting increase in net cost.

[5]BPA treats the amount of borrowing authority that it has "deferred" as part of its financial reserves. Deferred borrowing is created when BPA uses operating revenues to finance capital expenditures in lieu of borrowing. This temporary use of cash-on-hand instead of borrowed funds creates the ability in future years to borrow money, when fiscally prudent, to liquidate revenue funded activities.

authorizing legislation.[6] We refer to this repayment responsibility as irrigation debt. BPA's irrigation debt relates to its requirement to pay for irrigation capital costs that are determined to be beyond the ability of the irrigation water users to repay. Irrigation debt is generally due up to 60 years after completion of the construction of the irrigation facilities and is to be repaid at zero-percent interest. The estimated balance of this obligation is $841 million as of September 30, 1996. BPA's first payment of $25 million to the Treasury for irrigation debt is currently planned to be made in fiscal year 1997; an additional payment of $10 million is due in fiscal year 2001. The remaining $806 million is due after fiscal year 2001. Although irrigation debt is scheduled to be recovered from power revenues, BPA does not view irrigation debt as a power cost. Instead, BPA discloses this debt in the notes to the financial statements under "Commitments and Contingencies." However, if BPA recovers these amounts through its rates, these costs and revenues will be reflected in its financial statements. To the extent irrigation debt is recovered through electricity rates, BPA's power customers are subsidizing irrigators.

The federal government would incur a future loss on direct financial involvement if BPA failed to make payments on federal debt.

Indirect Financial Involvement

BPA had nonfederal debt of about $7.1 billion at September 30, 1996. This debt resulted from BPA's use of its contracting authority to acquire all or part of the generating capability of power projects of other entities. Under this arrangement, BPA contracts to pay for all or part of the annual project budgets, including debt service, whether the projects are completed or not. Approximately $4.24 billion of this total relates to three nonoperational and canceled nuclear projects, and an additional $2.54 billion to one operating nuclear plant. The remaining amount of about $321 million is for financing of small hydroelectric projects and conservation measures. The nonfederal debt is not explicitly guaranteed by the federal government; however, the financial community views this debt as having an implicit federal guarantee.

[6]Project-specific authorizing legislation determines how the costs of constructing reclamation projects are allocated and how repayment responsibilities are assigned among the projects' beneficiaries. Collectively, the Reclamation Project Act that is generally applicable to all projects and the statutes authorizing individual projects are referred to as reclamation law. In implementing reclamation law, the Bureau of Reclamation is guided by its implementing regulations, administrative decisions of the Secretary of the Interior, and applicable court cases. The Columbia Basin Project Act provides for BPA to use its power revenues to repay Treasury a certain portion of the capital costs allocated to completed irrigation facilities that are determined by the Secretary of the Interior to be beyond the ability of the irrigators to repay (irrigation assistance).

For this indirect involvement, the federal government would incur future losses for unreimbursed costs related to any actions it took to prevent default on nonfederal debt service payments or breach of contract on nonfederal debt by BPA.

Risk of Loss From BPA Is Remote Through Fiscal Year 2001

As a result of existing customer contracts, an MOA that put a ceiling on fish and wildlife mitigation costs and large financial reserves, we believe that the risk of any significant loss to the federal government from BPA is remote through fiscal year 2001.

Customer Contracts

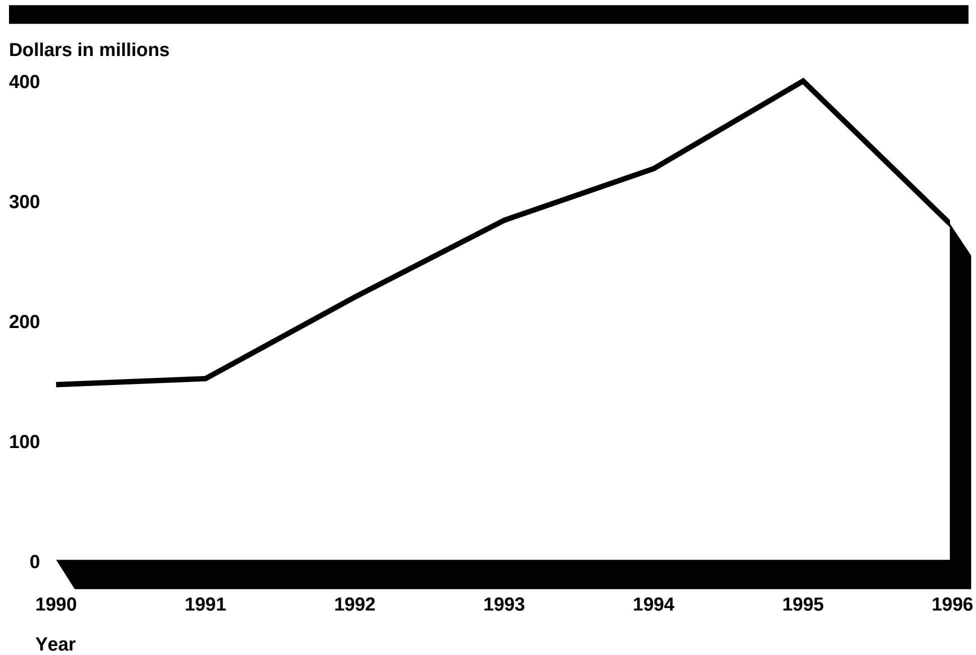
BPA has succeeded in signing most of its preference customers and industrial customers to contracts through fiscal year 2001. According to BPA, its new contracts make more extensive use of “take or pay” provisions than the old contracts. Such provisions require the customer annually to buy a specified, minimum amount of electricity at a set price. The contracts provide a substantial economic certainty to BPA in terms of the revenues that can be expected through fiscal year 2001. BPA projects that firm power sales to these customers will secure $1.14 billion annually through fiscal year 2001, or approximately 63 percent of each year’s total power revenue. The nature of these contracts and the certainty they provide strongly mitigate the possibility of financial loss to the federal government through fiscal year 2001.

Fish and Wildlife Costs

BPA bears substantial financial responsibility for measures to protect fish and wildlife populations and to mitigate damage to Pacific Northwest fish stocks affected by the construction and operation of the Federal Columbia River Power System. These costs include (1) outlays to fund operating and maintenance and capital costs for fish and wildlife mitigation and protection programs and (2) revenues BPA has forgone and related costs it has incurred because of restrictions on the operations of the hydroelectric dams, which generate the power marketed by BPA. For example, BPA’s total fish and wildlife costs in fiscal year 1996 were $278 million, including outlays of $176 million to fund fish and wildlife programs and $102 million in forgone revenues and related costs.

Escalation of these costs in recent years has placed considerable financial strain on BPA. Figure VIII.1 shows the trend of these costs, which include both funding outlays for fish and wildlife programs and revenues forgone because water was used for fish and wildlife purposes rather than hydropower production.

Figure VIII.1: BPA Fish and Wildlife Costs, Fiscal Years 1990-1996



As figure VIII.1 shows, these costs have increased significantly over time, from $146 million in fiscal year 1990 to $399 million in fiscal year 1995. Fiscal year 1996 saw a decrease in costs to $278 million, primarily because a large volume of water was available that year for both fish and wildlife mitigation and power production.

To address the problem of rising fish and wildlife-related costs, BPA entered into a MOA with the National Marine Fisheries Service, the U.S. Army Corps of Engineers, the Bureau of Reclamation, and the U.S. Fish and Wildlife Service in September 1996. The MOA limited BPA's fish and wildlife related funding responsibility and helped make it possible for BPA to offer contracts to its preference customers for fiscal years 1997 through 2001 at a reduction that averaged 13 percent, in comparison to rates prevailing in fiscal year 1996.

The MOA's annual total cost includes an agreement to limit actual funding outlays for fish and wildlife costs to an average of $252 million per year. In addition, BPA agreed to absorb additional costs in the form of forgone hydropower revenues resulting from water being used for fish and wildlife-related purposes and the cost of power purchases made necessary because of the fish protection effort.

Another factor adds to BPA's ability to control its fish and wildlife-related costs. In each year since the passage of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) (Pub. Law No. 96-501) in 1980, BPA has funded fish and wildlife related costs through rates. According to BPA, it had not recouped the portion of such expenditures that are attributable to the nonpower portion of the federal system's multiple purpose projects. Starting with fiscal year 1994, BPA began recouping these costs by taking credits against its annual Treasury payment. The credits BPA has taken were $19 million for fiscal year 1994, $56 million for fiscal year 1995, and $31 million for fiscal year 1996.[7]

The MOA describes a "Fish Cost Contingency Fund," which is available to BPA in certain situations. The fund consists of $325 million in credits that BPA is authorized to take against amounts otherwise payable by BPA to the Treasury. The amount in the fund is BPA's estimate of the portion of fish and wildlife-related expenditures that BPA made in the years prior to 1994 that were related to the nonpower purposes of the dams. BPA has not yet found it necessary to use the contingency fund. According to BPA, the MOA expires in fiscal year 2001, but the fund does not.

The MOA envisions the possibility that unforeseen events may make more fish and wildlife mitigation funding necessary, but does not specify what the funding source will be. It states that the parties to the MOA, along with the Pacific Northwest Electric Power and Conservation Planning Council[8] and the region's Indian tribes, should attempt to reach agreement on how additional funding is to be provided. If no agreement can be reached, the MOA provides that BPA is to recommend a funding mechanism to the Office of Management and Budget and the Council on Environmental Quality.

[7]The amounts for fiscal years 1995 and 1996 are estimates. BPA is in the process of determining what the final amounts will be.

[8]The Northwest Power Act established the Pacific Northwest Electric Power and Conservation Planning Council to provide guidance to BPA in its power planning and fish and wildlife program and other responsibilities. The Council consists of members appointed by the primary states served by BPA.

It is uncertain whether the MOA will be renewed or extended before it expires in fiscal year 2001. As long as this MOA remains in force, it provides BPA with protection against fish and wildlife-related costs exceeding the limit established in the agreement.

Financial Reserves

BPA currently has substantial financial reserves.[9] The agency had a $278 million cash and deferred borrowing authority balance at the end of fiscal year 1996. Because water for the hydropower system has been plentiful, BPA expects to have a cash and deferred borrowing authority balance at the end of fiscal year 1997 of about $400 million. In addition, the $325 million Fish Cost Contingency Fund discussed previously provides a supplementary financial reserve. These reserves provide BPA with the flexibility to deal with its operating risks.

However, BPA's reserves could be decreased by factors such as lawsuit settlements, and BPA's reserve levels have, in the past, varied considerably over time. An example of this was the decrease from an $877 million balance at the end of fiscal year 1991 to a $221 million balance at the end of fiscal year 1993. Also, deferred borrowing authority may be useful in the short term to provide liquidity, but, since it results in additional debt, is not a long-term solution to financial difficulty.

Risk of Loss Is Reasonably Possible After Fiscal Year 2001

Because of risks from the expiration of customer contracts, market uncertainties, BPA's high fixed costs, and upward pressure on other expenses, the risk of loss to the federal government increases significantly after fiscal year 2001. Despite a number of factors that mitigate this risk, we believe it is reasonably possible the federal government will incur losses relative to BPA after fiscal year 2001.

Customer Contracts Expire in Fiscal Year 2001

In fiscal year 2001, nearly all of BPA's power contracts with customers will expire. In that year, BPA projects firm power revenues from all customers totaling $1.58 billion. In the following year, should no contract renewals occur, only $286 million in firm power revenues will be contractually committed—a reduction of 82 percent. BPA has acknowledged this risk and is attempting to construct new contracts and have them signed before the current contracts expire. This effort is the result of a December 1996 study

[9]BPA financial reserves include cash and deferred Treasury borrowing authority, and the Fish Cost Contingency Fund constitutes a supplementary financial reserve, available in specified emergency situations. Deferred borrowing authority is similar to an unused line of credit.

called the Comprehensive Review of the Northwest Energy System (Comprehensive Review).

The Comprehensive Review was conducted at the direction of the governors of the four primary states that BPA serves and included an evaluation of what BPA's role should be in the Pacific Northwest energy market. One of the study's recommendations was that BPA devise "subscription contracts." These contracts would be long-term (5 to 20 years) and would offer benefits to "subscribers"—such as the ability to purchase from BPA at cost when costs are below market levels—and would help assure BPA's financial stability. BPA and its customers are participating in a work group that is developing the subscription contract concept. BPA's goal is to have the subscription process implemented and new contracts signed before the existing contracts expire.

If a significant amount of BPA's power is not contractually obligated in the future, BPA could be subject to considerable financial risk. If customers can find cheaper power sources, they might opt to leave BPA. The agency could find itself in a situation in which it has no guaranteed, stable market for its power, and could be unable to sell power on the open market at prices that allow full cost recovery.

Significant Risk From Market Uncertainties

BPA faces substantial risk from the uncertainties of the wholesale electricity marketplace. Among these risks are the future production cost of gas-fired generation plants, the existence of surplus electric power in the geographic area in which BPA operates, and the effects of retail open access on BPA and its customers.

Natural Gas Production Costs and Surplus Power

One of the key market uncertainties that will determine whether cheaper power will be available in the future is the production cost of gas-fired generation plants. This generation source has become increasingly competitive due to low natural gas prices and improving gas turbine technology. Natural gas prices in the Pacific Northwest are low due to several factors, including a large supply coming from Canada. Also, recent technological advances have improved the efficiency of gas turbines by more than 50 percent. According to BPA, natural gas-generated power has driven down the price of wholesale electricity and resulted in customers obtaining some of their power at rates well below BPA's current rate.

BPA officials stated that natural gas prices will be one of the most important variables regarding future competitiveness. In its "Future

Focus" planning effort, BPA researched available studies predicting future gas prices and discovered that there is a wide range of predictions. BPA selected what it deemed to be the most credible high-range and low-range predictions for its planning purposes. BPA concluded that it could remain competitive—even assuming low prices of gas in the future—if it can lower its costs to 2 cents per kilowatthour (kWh). BPA's Administrator told us that achieving this cost level is a primary organizational goal.

The price of natural gas was a primary variable in a 1996 study done for BPA. The study used three gas price escalation scenarios: base, low, and high. The base scenario assumed that gas prices would increase at the rate of inflation. The low-price scenario assumed that gas prices would be constant in nominal dollars through fiscal year 2000 and would increase at the rate of inflation thereafter. The high-price scenario assumed that gas prices would increase at 1.8 percent per year above the rate of inflation. The study generally found that BPA would not experience stranded costs[10] if gas prices escalated as assumed in the base and high scenarios. However, under the low-price scenario, BPA would have stranded costs. In that scenario, gas prices were assumed to be low, technology was assumed to make new lower-cost gas plants feasible, and the demand for electricity was assumed to be low.

According to BPA, surplus power, partially caused by record high river conditions and high hydropower production in the Pacific Northwest, is also driving down the price of wholesale power. Because utilities still are able to pass on fixed costs to captive retail customers, surplus wholesale power is being sold on a marginal cost basis. According to BPA, other utilities and power brokers are offering wholesale power for as low as 1.5 cents per kWh, which is lower than BPA's price for sales of comparable products at the current firm rate of 2.14 cents per kWh. It is uncertain whether surplus power and low cost natural gas generation will continue to drive down wholesale power prices after fiscal year 2001.

Effects of Retail Open Access

The possibility of retail open access adds to future uncertainty about the competitive environment in which BPA and its customers will operate. BPA sells wholesale power to utilities, which then resell it on a retail basis. Retail open access—which would provide retail customers the freedom to choose among suppliers—could result in BPA's customers being uncertain about the size of their own future retail sales. This uncertainty would make it unattractive for customers to sign long-term contracts with BPA

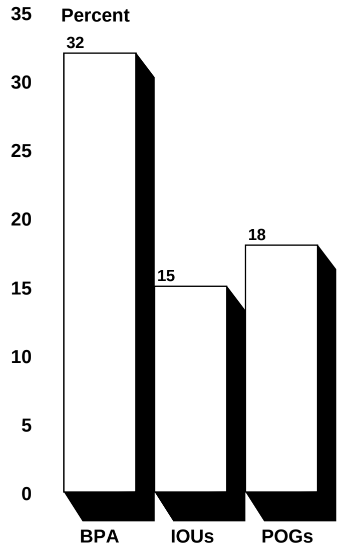
[10] As defined by the Federal Energy Regulatory Commission (FERC), a stranded cost is any legitimate, prudent, and verifiable cost incurred by a public or transmitting utility that is no longer economically viable in a competitive wholesale environment.

until they are reasonably assured of a stable, predictable retail customer base. However, even without long-term contracts, BPA is likely to remain a major supplier. All four states that constitute BPA's primary service area are considering some form of retail open access, and, under current law, retail open access will be decided on a state-by-state basis. However, the Congress is considering various proposals regarding the approach to retail open access that would be applied nationally.

BPA's Substantial Financing Costs Continue

BPA faces substantial risk beyond fiscal year 2001 because a large portion of its operating costs are fixed and therefore beyond management's control. The consequence of this lack of financial flexibility was demonstrated in fiscal years 1994 and 1995, when decreasing electricity prices resulted in BPA losing sales to other providers. Interest expense is BPA's second-largest expense (behind its operations and maintenance expense) and represents BPA's largest fixed cost. In fiscal year 1996, BPA paid approximately $766 million in interest expense on its $17.2 billion in debt. This level of expense means that BPA used 32 percent of its revenues in fiscal year 1996 to pay the interest on its debt. As shown in figure VIII.2, BPA's financing costs to revenue ratio is higher than those of investor-owned utilities (IOUs) and publicly-owned generating utilities (POGs), whose ratios were 15 and 18 percent (on a nationwide basis), respectively.

Figure VIII.2: Financing Costs as a Percentage of Revenues for BPA, IOUs, and POGs



Source: Developed by GAO based on data from BPA's 1996 annual report and national 1995 POG and IOU data from the Energy Information Administration (EIA).

BPA's relatively high financing costs mean that it has less flexibility than IOUs and POGs to reduce costs and hence lower rates to respond to competitive pressures. For example, BPA officials told us that it lost customers in fiscal years 1994 and 1995 as a result of its inability to lower rates in response to falling electricity prices in the Pacific Northwest.

It is important to note that a substantial portion of BPA's debt and interest expense relates to the construction of nonoperating nuclear plants. BPA has over $4.2 billion invested in these plants. Interest expense associated with these plants amounted to over $230 million in fiscal year 1996. This relatively high level of interest expense can be expected to continue for the foreseeable future, greatly limiting BPA's ability to react to falling electricity prices. Also, new borrowing and the potential need to refinance BPA's Treasury bonds as they mature could expose BPA to the risk of rising interest rates and even higher financing costs.

BPA is scheduled to have nearly all of its nonfederal debt, including the debt associated with nonoperating nuclear plants, paid off by fiscal year 2019. Substantial decreases in scheduled nonfederal debt servicing begin in fiscal year 2013. Specifically, these debt service costs are expected to decrease from an average of about $570 million annually from fiscal years 1997 through 2012, to an average of about $304 million annually from fiscal years 2013 through 2018. In fiscal year 2019, BPA's scheduled debt service payment declines to less than $3 million and decreases further in the following years. If BPA is able to make these payments as scheduled, all else being equal, its fixed financing costs would be more in line with those of its competitors. This would result in a reduction of risk to the federal government over time.

BPA Faces Upward Pressure on Other Expenses After Fiscal Year 2001

Several factors combine to increase the financial pressure faced by BPA in the period beyond fiscal 2001. Among them are the expiration of the fish and wildlife MOA, the inclusion of the full cost of pension and postretirement health benefits in rates, payments of irrigation debt, payments to the Colville Tribes, and possible payments to settle a lawsuit. Taken individually, these factors may not place substantial pressure on BPA's ability to remain competitive, but in combination they could have this effect.

It is uncertain whether an agreement similar to the current MOA that stabilizes fish and wildlife costs will be entered into after the present one expires. Absent this agreement, BPA is at risk if costs escalate beyond the MOA limits after fiscal year 2001.

BPA also faces substantial new or additional costs after fiscal year 2001. First, it plans to implement a phased-in approach to recovering the full cost of pension and postretirement health benefits in fiscal year 1998, but will defer full recovery until fiscal year 2002 when $55 million will be due. To completely recover obligations for fiscal years 1998 through 2001, an additional $35 million will be due in fiscal year 2003. Other costs that will be incurred over the several decades after fiscal year 2001 include an estimated $806 million of irrigation debt and BPA's estimated $396 million in payments to the Confederated Tribes of the Colville Reservation for its share of Grand Coulee Dam revenues. The payments to the Tribes are to be made annually, and are based on an agreed-upon range of prices for electricity and the Grand Coulee Dam's power generation for each year.

The pending lawsuit against BPA by Tenaska Washington Partners, II L.P. (Tenaska) could result in additional financial pressure on BPA. In 1994, BPA and Tenaska entered into a power purchase agreement under which Tenaska was to build and BPA was to purchase the output of a combustion turbine generating plant. In 1995, BPA gave notice to Tenaska that "its purpose in acquiring the resource had been frustrated as a result of the loss of a significant portion of the load which the resource had been acquired to serve and because the resource could not operate as intended within the Federal System because of operational requirements imposed by the 1995 (Endangered Species Act) Biological Opinion after the power purchase agreement was executed."

Tenaska and Chase Manhattan Bank (which had arranged the financing for the canceled project) sued BPA for breach of contract. BPA paid $115 million to Chase in settlement of Chase's claim. BPA has entered binding arbitration with Tenaska to settle its claim. The $115 million payment to Chase is to be offset by any award to Tenaska. According to the Notes to the Financial Statements in BPA's 1996 annual report, BPA believes that the factual and legal assertions by Tenaska in support of its $1.125 billion claim are without merit. However, if the arbitration of this lawsuit results in a judgment against BPA in an amount substantially in excess of $115 million, it would increase the risk of financial loss to the federal government.

Mitigating Factors Reduce Long-term Probability of Loss

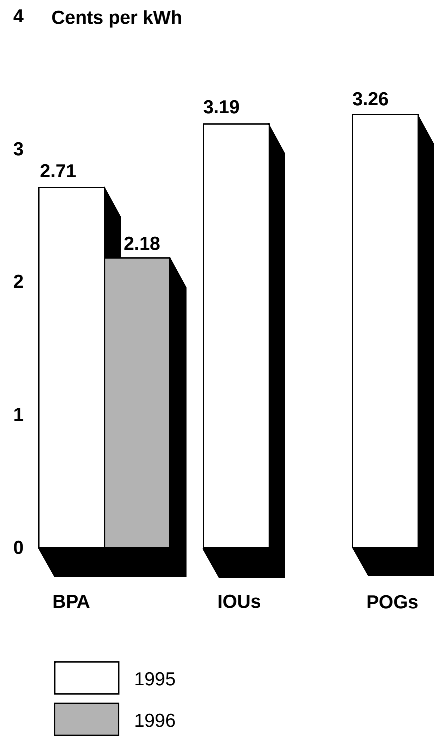
Several factors mitigate the federal government's risk of loss from BPA. These factors include inherent cost advantages, management actions that reduce operating costs, and BPA's extensive transmission system. Because of these factors, we believe the risk of loss to the federal government after fiscal year 2001 is reduced, but is still reasonably possible. However, beginning in fiscal year 2013, nonfederal debt levels are scheduled to decline substantially. If BPA pays off its nonfederal debt, all else being equal, its fixed financing costs would be more in line with those of its competitors. This would reduce the risk to the federal government.

Cost Recovery Structure and Inherent Advantages Contribute to Low-Cost Power

As shown in figure VIII.3, in 1995 BPA's average revenue per kWh was more than 15 percent lower than IOUS and POGS in the primary North American Electric Reliability Council (NERC)[11] regions in which BPA operates. Although BPA's average cost of production is substantially below that of other utilities, as indicated by its favorable average revenue per kWh ratio, it is currently facing significant competition from electricity that is being sold at marginal costs. If the supply of surplus power subsides and natural gas prices rise, which BPA believes will happen, BPA's low average production costs should significantly improve its long-term competitive position.

[11] We used the 1995 NERC configuration because the latest available data on average revenue per kWh by NERC region are from 1995. NERC's configuration changed in 1996. See appendix III for a further discussion.

Figure VIII.3: Average Revenue per kWh of Wholesale Power Sold, 1995
(Revenues in cents)



Source: Developed by GAO based on data from BPA's 1996 annual reports, preliminary (unaudited) 1995 IOU data from EIA, and POG data from the American Public Power Association (APPA).

BPA has inherent cost advantages compared to nonfederal utilities. As discussed in volume 1 of this report, in 1996 BPA did not charge through to rates nearly $400 million of costs associated with producing and marketing federal power. These unrecovered power costs give BPA a significant competitive advantage compared to nonfederal utilities.

BPA's costs are also minimized by the fact that it markets power generated mainly by hydroelectric plants built 30 to 60 years ago, while other utilities are primarily dependent on coal and nuclear generating plants. Table VIII.2 shows the contrast between BPA and other utilities in the percentage of power coming from different generating sources.

Table VIII.2: Percentage of Net Generation for BPA and Other Utilities, 1996

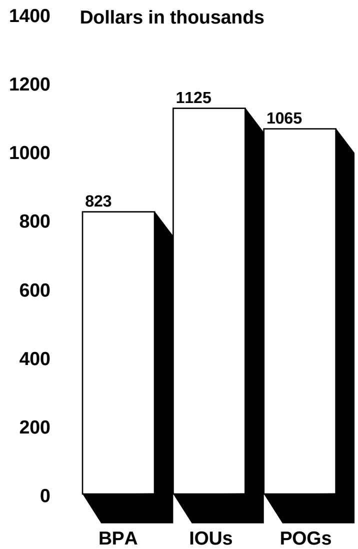
	Coal	Nuclear	Gas	Hydro	Other
BPA	0	7.4	0	92.6	0
Other utilities	57.5	24.2	9.7	6.1	2.5

Source: BPA for BPA data, EIA for other utilities data.

The hydroelectric plants that generate the power marketed by the BPA and the other PMAs have significant cost advantages over coal and nuclear generating plants, which are used to generate over 81 percent of the electricity in the United States. For example, BPA's hydroelectric plants, which were built decades ago, had relatively low construction costs. To show the relatively low capital cost of the hydropower plants, which produced nearly 93 percent of the power marketed by BPA in fiscal year 1996, we compared BPA's investment in utility plant per megawatt of capacity for these plants to those of IOUs and POGs nationwide. As shown in figure VIII.4, BPA has invested less in plant per megawatt of generating capacity than the other utilities.[12] Appendix II describes the methodology used for computing the ratios in figure VIII.4.

[12]Our analysis excluded IOU and POG nuclear plants that are mothballed and thus provide no capacity while resulting in significant capital costs. Mothballed nuclear plants can be either incomplete plants that have had construction terminated or completed plants that have been shut down either temporarily or permanently. Under generally accepted accounting principles, these costs are either written off or, if deemed allowable by the applicable regulator, are classified as "regulatory assets" and included in rates through amortization. Inclusion of these "regulatory assets" would have increased the POG and IOU investment.

Figure VIII.4: Investment in Utility Plant per Megawatt of Generating Capacity



Source: Developed by GAO based on data from BPA's 1996 annual report and 1995 IOU and POG data from the EIA.

BPA's low investment in utility plant per megawatt of generating capacity contributes to BPA's relatively low average revenue per kWh, as shown in figure VIII.3. As discussed earlier, because of BPA's investment in nonoperational nuclear plants, BPA's overall production costs are higher than would be the case in the absence of these investments. This is because BPA has invested over $4.2 billion in these nonoperating plants, which, while producing no marketable power, incur substantial interest expense. BPA's investment in utility plant per megawatt of generating capacity, as shown in figure VIII.4, would be substantially lower—$630,000 per megawatt—if the $4.2 billion of nonoperating plant investments were excluded.

Another major reason that hydroelectric plants result in lower production costs is the cost of fuel. This is particularly important when comparing hydroelectric plants to coal plants because the cost of coal is a major operating expense for most other utilities. Nuclear fuel is also a significant cost, although not nearly as large a cost as coal. In 1995, POGs' fuel costs represented about 11 percent of operating revenues, while IOUs' fuel costs represented 16 percent of operating revenues. BPA, on the other hand, has the benefit of marketing power primarily from hydroelectric plants, which do not have an associated fuel cost.[13]

A significant disadvantage of hydroelectric generation is the unpredictability of water availability. BPA's historical sales figures demonstrate the dramatic effect that droughts can have on revenues. For example, 1996 was the best water year since 1974, a fact which was crucial to BPA's attaining $96 million in net revenues for the year. Due in part to the additional power generated, BPA's sales of surplus and nonfirm power increased 296 percent over the previous year. As previously discussed, another significant disadvantage of BPA's hydropower generation is the cost associated with unique fish population improvement measures, which BPA estimated was $216 million in 1996.

Another key advantage for BPA is that as a federal agency, it generally does not pay taxes. In contrast, IOUs do pay taxes. According to the EIA, in 1995 IOUs paid taxes averaging about 14 percent of operating revenues. This average varies significantly from state to state due to differing state and local tax laws. Taxes paid by IOUs include federal and state income taxes, real and personal property taxes, corporate franchise taxes, invested capital taxes, and municipal license taxes. A specific example of a tax advantage BPA has relates to its nonfederal debt. The interest income earned by holders of the bonds issued by the Washington Public Power Supply System is not subject to federal, personal, and some state income taxes. This debt carries an interest rate that is lower than the interest rate applicable to debt of similar risk but without the tax-free provisions. This provides a measure of benefit to BPA, which is contracted to pay the Supply System its debt service on the bonds.

POGs, as publicly owned utilities, typically do not pay income taxes because they are units of state or local governments. However, many POGs do make payments in lieu of taxes to local governments. A study[14] of 670 public distribution utilities showed that the median net payments and contributions as a percentage of electric operating revenue were 5.8 percent.

Management Actions

BPA management has taken several actions that are intended to address the intense wholesale electricity competition in the Pacific Northwest. These

[13]Approximately 7 percent of the electricity marketed by BPA in fiscal year 1996 was produced from nuclear energy.

[14]1994 Payments and Contributions by Public Power Distribution Systems to State and Local Government, American Public Power Association, March 1996.

actions have helped make it possible for BPA to lower rates by about 13 percent for fiscal years 1997 through 2001. Management's actions have included setting cost reduction targets, reducing both agency and contractor staff, and refinancing nonfederal debt and Treasury bonds.

Since 1994, BPA management has set cost reduction targets. To meet those targets, BPA has analyzed its various spending plans—such as its fiscal year 1995 budget submission and expenses shown in rate proposals—and has reduced the expenses that were shown for future years in those plans. The cumulative total, according to BPA's 1996 annual report, is a cost reduction of $600 million per year. BPA states that this reduces expenses that would otherwise have been incurred by $600 million per year during fiscal years 1997 through 2001 and allowed for a 13-percent rate decrease for those years. The cuts in planned expenses have been widespread to include BPA's marketing and production, conservation, transmission, and other activities.

Staff reductions are also part of management's plan. According to BPA, it has reduced its staff from a total of 3,755 full time equivalents (FTEs) in March 1994 to a total of 3,160 by the end of fiscal year 1996. The agency plans a further reduction to 2,755 FTEs in fiscal year 1999. In addition, BPA told us that it has reduced its contractor full time equivalents (CFTEs) from 1,911 in fiscal year 1994 to 1,077 at the end of fiscal year 1996.

In addition, BPA has refinanced its nonfederal debt and Treasury bonds to keep its interest expense as low as possible. BPA also plans to use revenue financing (funding capital acquisitions from current revenues) in some instances to reduce future financing costs. These plans and actions are consistent with those taken by IOUs in preparation for competition.

BPA's management is also working with customers to come to an agreement on phasing out the residential exchange program. This program allows certain utilities access to BPA's power on an "exchange" basis. If the utilities' average power costs are higher than the cost of BPA power, the utilities are authorized to "exchange" a certain limited amount of their higher cost power with BPA. BPA reimburses the utilities for the difference between the higher costs and BPA's cost. The benefiting utilities are to assure that the exchanged power is sold only to residential and small farm customers. This program cost BPA $196 million in fiscal year 1996. The elimination of the program is not, however, within BPA's discretion. The program is mandated by the Northwest Power Act, and legislative action would be required to eliminate it.

Transmission System

BPA's extensive transmission system is a significant mitigating factor in assessing the risk of loss to the federal government. BPA owns 75 percent of the total bulk power transmission line system in the region. Ownership of such a large portion of the Pacific Northwest's transmission capacity should provide BPA with considerable ability to generate fees for access to this system when wholesale electricity competition is fully realized. BPA has advised us that in the event that it is unable to sell its power at a level that recovers all costs, it might be able to use its massive transmission system to recover stranded costs. This could involve allocating stranded generation costs, in whole or in part, to transmission charges for a period of years.

One uncertainty regarding stranded cost recovery relates to FERC's requirement that utilities separate transmission and generating functions. BPA has separated these functions administratively, but new legislation would be required to establish two separate legal entities—for instance, two government corporations. The use of transmission revenues for stranded cost recovery could depend on the provisions of this legislation.

Risk of Loss From Teton Dam Project Is Probable

We identified one small project that serves BPA for which we believe financial loss to the federal government is probable. This project, Teton Dam, was a multipurpose project on the Teton River in Idaho built by the Bureau of Reclamation. The dam failed in 1976 when it was substantially complete, resulting in flooding, loss of life, and loss of the facilities. Had the project been completed, power-related construction costs of about $7.3 million and irrigation costs of about $56.6 million would have been included in BPA's power rates for eventual repayment to Treasury.

Since the failure of the project in 1976, these costs have been carried on the books of the Bureau of Reclamation as construction work-in-progress (CWIP). While CWIP assets normally accrue interest charges, the Teton project has accrued no interest since 1976. We estimate that since that time, interest charges of about $5 million, at the project interest rate of 3.25 percent, would normally have been paid to Treasury.

The project's power-related construction costs are in the Federal Columbia River Power System's consolidated financial statements in the "Other Asset" category and are part of BPA's appropriated debt balance. However, provisions for recovery of this amount have not been made. BPA officials told us that since the project was not formally completed and placed in service, its costs cannot be put into BPA's rates.

A Bureau of Reclamation official told us that it has no plans for further construction at the site and that the project should be written off. According to this official, however, this would require deauthorization of the project by the Congress. Regardless of whether the project is deauthorized, we believe these costs are unlikely to ever be recovered.

Risk Assessment for the Tennessee Valley Authority

At September 30, 1996, the Tennessee Valley Authority (TVA) had $27.9 billion of debt and $6.3 billion of deferred assets, which leaves TVA with far more financing and deferred assets than its potential competitors. The risk that TVA will cause the federal government to incur losses is remote as long as TVA retains a position in its service area that is protected from competition—similar to a traditional regulated utility monopoly.[1] However, if this position changes and TVA is required to compete at a time when wholesale prices are expected to be falling, its high fixed and deferred assets compared to neighboring utilities make it reasonably possible that the federal government would incur future losses.

The Federal Government's Financial Involvement

The federal government has financial exposure because of its nearly $28 billion of direct and indirect financial involvement with TVA. As shown in table IX.1, the federal government's direct financial involvement, which consists of appropriated debt[2] and Federal Financing Bank (FFB) debt, was about $3.8 billion as of September 30, 1996. The federal government's indirect financial involvement, which consists of TVA's public debt, was $24.1 billion as of September 30, 1996.

Table IX.1: The Federal Government's Financial Involvement in the Tennessee Valley Authority as of September 30, 1996

Dollars in billions

	Financial involvement		
Description	**Direct**	**Indirect**	**Total**
Appropriated debt	$0.6		**$0.6**
FFB debt	3.2		**3.2**
Public debt		$24.1	**24.1**
Total	**$3.8**	**$24.1**	**$27.9**

Source: TVA's fiscal year 1996 annual report.

[1]Regulated monopolies are permitted by the government when unregulated market forces (for example, economies of scale) would naturally drive the market from competition to monopoly. In such situations, the government designates a single seller of a well-defined product and regulates it to ensure delivery at acceptable prices.

[2]In the case of appropriated debt, TVA is required to repay all but $258.3 million of the appropriations that were used for capital investments, plus interest. TVA is not required to repay the entire appropriated debt balance because the federal government wanted to retain an equity interest in the assets of the corporation. However, these reimbursable appropriations are not technically considered lending by the Treasury and are not included in TVA's debt cap. TVA refers to this debt as "appropriation investment" and considers it to be equity. Accordingly, TVA considers the annual payments a reduction of equity capital and the annual return a dividend. For purposes of this report, we refer to the annual payments as debt (principal) payments and the annual return as interest expense.

Direct Financial Involvement

TVA's appropriated debt consists of appropriations that were primarily used to construct TVA's hydroelectric and fossil plants, transmission system, and other general assets of the power program. Substantially all of this debt was incurred from TVA's inception in 1933 through 1959 when the TVA Act was amended to give TVA the authority to "self-finance." The 1959 amendments to the TVA Act require TVA to make annual principal payments (currently $20 million) to Treasury from net power proceeds plus a market rate of return[3] (interest expense) on the balance of this debt. The annual principal payments are to continue until the debt is paid down to $258.3 million. TVA estimates that it will pay down its appropriated debt balance to $258.3 million by the year 2014. TVA is required to continue to pay annual interest on this balance but is not required to repay the remaining principal.

TVA's FFB debt stems from authority granted to it in the 1959 amendments to the TVA Act. The amendments authorized TVA to issue bonds, notes, and other evidence of indebtedness to the public and the government up to a total of $750 million. Since then, TVA's debt limit has been increased four times by the Congress: to $1.75 billion in 1966, $5 billion in 1970, $15 billion in 1975, and $30 billion in 1979. In 1994, TVA's Chairman announced that TVA would stop increasing its debt by October 1997. If this plan is achieved, TVA would have an internal cap on its debt that is about $2 billion below its $30 billion statutory debt limit. TVA's outstanding debt was incurred primarily to finance the construction of its nuclear program.

For direct involvement, the federal government would incur a future loss if TVA failed to make payments on its outstanding appropriated and FFB debt.

Indirect Financial Involvement

Like its FFB debt, TVA's authority to issue public debt stems from the authority granted under the 1959 amendments to the TVA Act. This debt has been issued primarily to finance the construction of TVA's nuclear power program. The federal government's involvement in this debt is indirect because, although the federal government does not explicitly guarantee this debt, the major credit rating agencies rate this debt as if it has an implicit federal guarantee. Therefore, TVA's public debt is rated based primarily on TVA's links to the federal government rather than on the criteria that would be applied to a stand-alone corporation. As a result, the private lending market has provided TVA with access to billions of dollars

[3]The annual rate of return (interest expense) on TVA's appropriated debt is based on the computed average interest rate paid by Treasury on its total marketable public obligations as of the beginning of each year. Total marketable obligations include all outstanding short-term and long-term marketable Treasury securities, including Treasury bills, notes, bonds, and FFB securities.

of financing at favorable rates. Debt service on TVA's public debt, which is payable solely from TVA's net power proceeds, generally has precedence over the payment of TVA's appropriated debt.

For indirect involvement, the federal government would incur future losses as a result of unreimbursed costs related to any actions it took to prevent default on the debt service requirements on TVA's outstanding public debt.

Risk of Loss From TVA Is Remote Under Current Structure

We believe there are two major factors that protect TVA from competition and result in TVA operating in a manner similar to a traditional regulated electric utility monopoly. First, in nearly all instances, TVA's contracts with its 160 distributors automatically renew each year and require that at least a 10-year notice be given before the distributors can switch to another power company. Second, TVA is exempt from the wheeling provisions of the Energy Policy Act of 1992. This exemption generally prevents other utilities from using TVA's transmission system to sell power to customers inside TVA's service area. TVA also has the added advantage of being able to set its own rates with a minimum of oversight. These protections and advantages result in TVA's service area being substantially without wholesale competition. We believe the risk of loss to the federal government is remote as long as TVA remains in this protected position.

Long-term Contracts Provide Stability and Ensured Cash Flow

TVA's wholesale contracts with its 160 distributors, representing 83 percent of TVA's load, are generally long-term, which assure it a relatively stable customer base and cash flow. Except for Bristol, VA, the wholesale power contracts between TVA and its distributors contain a 20-year term that automatically renews each year (referred to as the "evergreen" provision) and require that the distributors give TVA at least a 10- to 15-year notice of cancellation. This 10- to 15-year notice provision effectively locks the distributors into purchasing power from TVA since obtaining price quotes for power to be supplied beginning 10 to 15 years into the future is generally not feasible. All of the power contracts between TVA and its distributors are "full requirements" contracts that require the distributors to purchase all of their electric power from TVA.

TVA's Exemption From "Wheeling" Provisions Protects Against Outside Competition

TVA is further insulated from competition by a specific exemption from wheeling provisions of the Energy Policy Act of 1992. Under the act's provisions, the Federal Energy Regulatory Commission (FERC) can generally compel a utility to transmit ("wheel") electricity generated by another utility into its service area for sale to wholesale customers. The act acknowledges that with certain exceptions, TVA is legally prohibited from selling power outside its legislatively mandated service area (referred to as TVA's "fence") and therefore generally exempts it from having to transmit power from neighboring utilities to wholesale customers within TVA's service area. Under the TVA Act and the Energy Policy Act of 1992, TVA is authorized to allow other utilities to use its transmission lines to wheel power through its service area to other utilities, but is not required to allow other utilities to sell power to customers within TVA's service area.

TVA Can Set Rates With Minimum Oversight

Another significant advantage for TVA is that unlike other utilities, the rates TVA charges for its electric power are not subject to review and approval by state public utility commissions or FERC. TVA can, and in fact must under the TVA Act, set its rates to recover all power-related costs. Because the long-term "evergreen" contracts and the exemption from the wheeling requirements allow TVA to operate like a traditional regulated monopoly, TVA can set rates at whatever level it deems necessary to recover all costs and, to a certain extent, not face the same competitive pressures as other utilities. Despite this advantage, as is discussed in the next section, TVA has chosen to defer a substantial amount of costs to future years rather than beginning to recover these costs from ratepayers.

Risk of Loss Is Reasonably Possible Absent Protection From Competition

Based on discussions with industry experts and TVA officials, it appears unlikely that TVA will be allowed to maintain its current regulated monopoly-type structure indefinitely and, at some future point, will have to compete with other utilities. In a competitive environment, utilities that have low costs and the flexibility to adjust their rates to meet those being offered by other utilities are expected to be the most competitive. We believe TVA's substantial fixed costs and deferred assets will limit TVA's flexibility to continue to offer competitive rates and could impact its ability to recover all costs in a future competitive environment when wholesale prices are expected to be falling. Therefore, despite a number of mitigating factors, without protection from competition, we believe that it is reasonably possible under this scenario that the federal government would incur future losses as a result of its financial involvement with TVA.

High Fixed and Deferred Assets Would Impede TVA's Ability to Compete

TVA has chosen to defer costs related to its substantial nuclear investment to future years rather than currently including them among the costs being recovered from ratepayers and using the cash generated to pay down its debt. As a result, TVA had accumulated $28 billion of debt as of September 30, 1996, which resulted in over $2 billion of interest expense in fiscal year 1996.

The recovery of these deferred assets is being put off to the future and will most likely be scheduled to be recovered from ratepayers at a time when wholesale power rates are expected to be falling. By choosing to keep its rates stable over the last 10 years, TVA's resulting high fixed and deferred assets will leave it vulnerable to future competition, similar to the Bonneville Power Administration's (BPA) situation. As mentioned in appendix VIII, BPA's high fixed costs limited its flexibility to meet competitive challenges when electricity prices fell sharply in the Pacific Northwest in the last several years. Like BPA, we believe that TVA's high fixed and deferred assets would limit its flexibility to react to falling wholesale prices that are likely to result from competition. However, unlike TVA, BPA has no deferred nuclear assets.

Following is an assessment of several key ratios that demonstrate why we believe TVA's high fixed and deferred assets would make it vulnerable in a competitive environment.

Flexibility Ratios

To assess TVA's financial condition relative to its likely competitors, we compared certain flexibility ratios for TVA and 11 neighboring investor-owned utilities (IOUS).[4] First, we computed the financing costs to revenue ratio, which indicates the percentage of operating revenues needed to cover the financing costs of the entity. The financing costs for TVA consist of the interest expense on its outstanding debt. Due to the difference in the capital structure between TVA and the IOUS, we included preferred and common stock dividends in the financing costs for the IOUS because part of the IOUS' capital is derived from preferred and common stock and dividends represent the cost of this equity capital. TVA's capital, on the other hand, is derived primarily from debt. Next, we computed the fixed financing costs to revenue ratio, which indicates the percentage of operating revenues needed to cover the fixed portion of the financing

[4]According to industry experts, TVA's competition would most likely come from nearby utilities because of the cost of wheeling power. We recognize that utilities that do not border on TVA's service area, power marketers, and independent power producers (IPPs) also provide likely competition for TVA. However, we believe that comparing TVA to its neighboring IOUs provides a reasonable basis for assessing TVA's ability to compete. See appendix II for a description of these utilities.

costs. For this ratio, we excluded the common stock dividend paid by IOUs because these are not contractual obligations that have to be paid. For both of these ratios, the lower the percentage, the greater the financial flexibility of the entity.[5] Table IX.2 shows the results of this comparison.

Table IX.2: Comparison of Financial Ratios for TVA and Neighboring IOUs That Indicate Flexibility, Fiscal Year 1996

Utility	Financing costs to revenue (percent)	Fixed financing costs to revenue (percent)
TVA	35.3	35.3
American Electric Power	14.9	7.2
Carolina Power & Light	15.4	6.5
Cinergy	16.3	7.8
Dominion Resources	18.4	8.9
Duke Power	13.4	4.5
Entergy	16.7	11.0
Illinova	13.8	8.8
KU Energy	15.0	5.9
LG&E Energy	3.6	1.5
SCANA	18.6	8.4
Southern	15.7	7.6
IOU Summary		
Average	**14.7**	**7.1**
High	**18.6**	**11.0**
Low	**3.6**	**1.5**

Source: GAO analysis of 1996 annual reports.

As indicated by table IX.2, TVA's ratio of financing costs to revenue is more than twice as high as the average financing costs for neighboring utilities. TVA's ratio of fixed financing costs to revenue is almost five times higher than the average of its neighboring IOUs. All of TVA's financing costs are interest expense and thus are fixed in the short term. On the other hand, IOUs' common stock dividends are not contractual obligations that have to be paid. We recognize that short-term stock prices would be negatively impacted by an IOU's decision not to pay dividends. However, IOUs have this flexibility and some have elected this option in the past. These two ratios clearly show that because of high financing costs, TVA does not have the same level of flexibility as neighboring IOUs to lower prices to meet price competition.

[5]See appendix II for a description and methodology for calculating these ratios.

In addition to TVA's already relatively high financing costs, it also is exposed to substantial risk of rising interest rates. In fiscal year 1996, TVA's interest payments alone amounted to just over $2 billion, which represented about 35 percent of its fiscal year 1996 operating revenue. As TVA's approximately $28 billion in debt matures, the portion that is not repaid will likely need to be refinanced, thus exposing TVA to the risk of rising interest rates and even higher financing costs. However, if rates decline, TVA will experience a decrease in financing costs. For example, as of September 30, 1996, TVA had approximately $8 billion in long-term debt that will mature and need to be refinanced over the next 5 years. By the end of this 5-year period, for every 1 percentage point change in TVA's borrowing cost, its annual interest expense will increase or decrease by $80 million per year. In addition, as of September 30, 1996, TVA had about $2 billion of short-term debt that would also be subject to changes in interest rates.

Deferred Asset Ratios

In addition to the two flexibility ratios above, we computed the ratios shown in table IX.3 to compare the magnitude of TVA's deferral of costs compared to its most likely competitors. These ratios measure the relative amount of capital costs that will need to be recovered in the future via depreciation or amortization. We computed the accumulated depreciation and amortization to gross property, plant, and equipment (PP&E) ratio to show how much PP&E has been depreciated and recovered through rates at September 30, 1996. A higher ratio indicates that more capital costs have been recovered through rates. We also computed the deferred assets to gross PP&E ratio to show how much of total PP&E has not yet begun to be depreciated and taken into rates. In this case, a lower ratio indicates fewer deferred assets and a better competitive position.

Table IX.3: Comparison of Financial Ratios for TVA and Neighboring IOUs That Indicate Deferred Assets, Fiscal Year 1996

Utility	Accumulated depreciation/ amortization to gross PP&E (percent)	Deferred assets to gross PP&E (percent)
TVA	18.2	19.5
American Electric Power	39.8	1.9
Carolina Power & Light	37.2	1.9
Cinergy	36.4	1.8
Dominion Resources	37.5	1.1
Duke Power	37.3	2.5
Entergy	35.4	1.6
Illinova	34.7	6.2
KU Energy	42.0	2.5
LG&E Energy	37.2	1.5
SCANA	30.1	4.3
Southern	31.9	2.0
IOU Summary		
Average	**36.3**	**2.5**
High	**42.0**	**6.2**
Low	**30.1**	**1.1**

Note: See appendix II for a description of the methodology used to calculate these ratios.

Source: GAO analysis of 1996 annual reports.

TVA's ratio of accumulated depreciation and amortization to gross PP&E was 18 percent as of September 30, 1996, whereas similar ratios for the IOUs in the comparison group averaged 36 percent. This ratio shows that only half as much of TVA's capital costs, in percentage terms, have been taken into its rate base via depreciation and amortization compared to the average for IOUs.

The second ratio shows that TVA's deferred assets represent 20 percent of its gross PP&E, while the ratio for the 11 IOUs averaged just 3 percent.[6] TVA's decision to not begin recovering the costs of the deferred nuclear plants when construction was stopped has increased the costs that must be recouped in the future. These ratios show that while TVA has deferred substantial costs, its potential competitors have written down the assets they deem to be uneconomical at a much faster rate, which results in these

[6]The IOUs deferred assets primarily represents construction work-in-progress.

utilities recovering costs at a much greater pace than TVA and thus having greater financial flexibility in the future.

The primary component of TVA's deferred assets is $6.3 billion in capital costs for its nonproducing nuclear assets (Watts Bar 2 and Bellefonte 1 and 2 nuclear units[7]). TVA has deferred these costs based on its unique interpretation and application of accounting principles. Despite the fact that there are no other deferred nuclear plants in the United States, TVA is treating Watts Bar 2 and the Bellefonte units similar to construction work-in-progress (CWIP). As such, the recovery of the costs of these assets will not begin until the units are either completed and placed in service or canceled.

In December 1994, TVA determined it would not, by itself, complete Bellefonte units 1 and 2 or Watts Bar 2 as nuclear units. However, TVA is still studying the potential for converting Bellefonte to a combined cycle plant and/or joint-venturing with a partner for completion of the plant. This study is scheduled to be completed by the fall of 1997. TVA also concluded, as part of its Integrated Resource Plan, that Watts Bar 2 should remain in deferred status until completion of the Bellefonte study.

We believe that the $6.3 billion of costs are appropriately capitalized as an asset in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. However, as we reported in 1995 (See our report Tennessee Valley Authority: Financial Problems Raise Questions About Long-term Viability (GAO/AIMD/RCED-95-134, August 17, 1995)), we believe that it is unlikely that these projects, which have not had any construction work done for 9 years, will ever be completed as nuclear units. SFAS No. 90, Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs requires that "When it becomes probable that an operating asset or an asset under construction will be abandoned, the cost of that asset shall be removed from construction work-in-process." In our judgment, SFAS No. 90 requires that TVA's $6.3 billion of costs be reclassified from CWIP to "regulatory assets" and that amortization begin immediately. We believe that TVA's continued exclusion of these costs from charges to ratepayers reduces the likelihood of recovery from ratepayers and puts the federal government at increased risk of absorbing these costs in the future.

[7]TVA suspended construction activities on Watts Bar 2 in 1988, and the unit is currently in lay-up status. In 1988 and 1985, TVA deferred construction activities at Bellefonte 1 and 2, respectively.

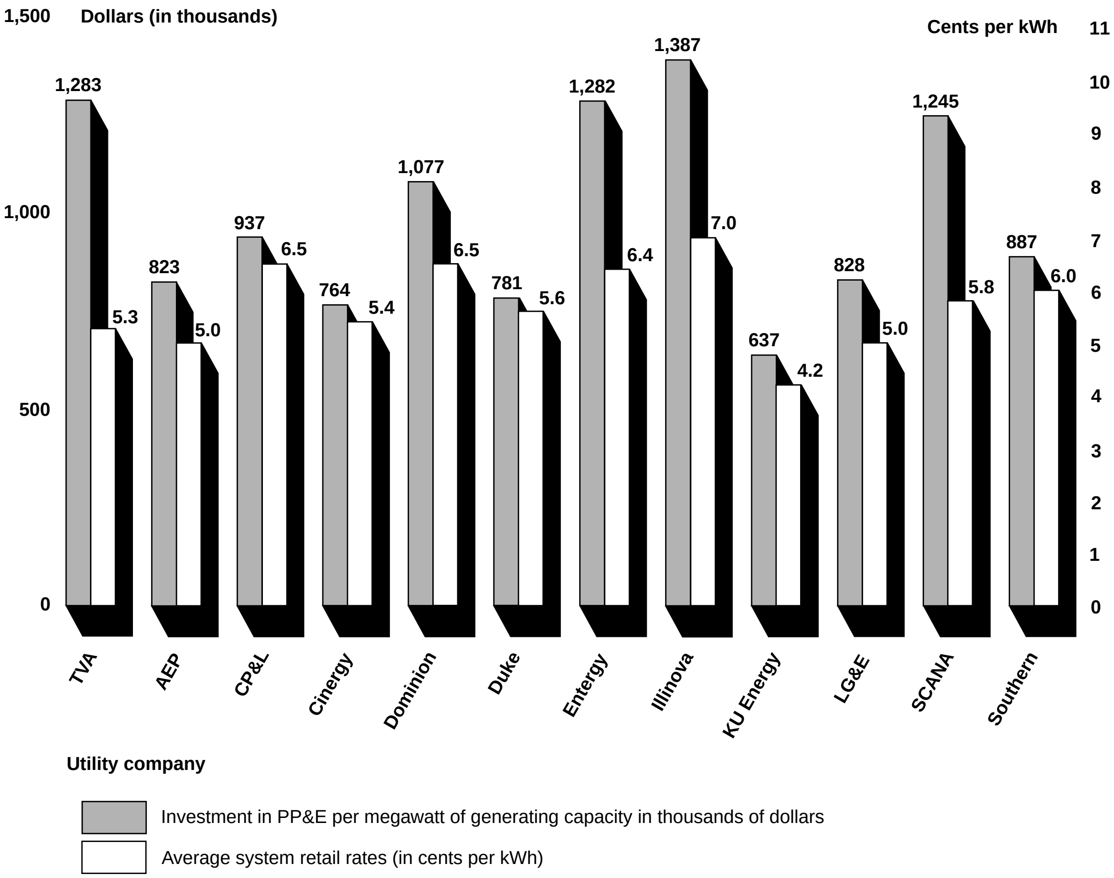
TVA charges the costs of its PP&E and canceled plants to ratepayers through depreciation and amortization expenses. TVA is required by law to set rates so that power revenues cover all operating expenses, including depreciation and amortization. While the nonproducing nuclear assets are not presently being depreciated or amortized, the annual interest expense from the debt associated with these assets is included in TVA's current charges to ratepayers. By not recovering the costs of its deferred nuclear units from ratepayers and using the cash to pay off debt in prior years, TVA has developed high fixed costs and deferred assets which will place upward pressure on TVA's rates at a time when power rates are expected to be falling.

Investment in PP&E Per Megawatt of Generating Capacity

Finally, to analyze TVA's competitiveness with its 11 neighboring utilities, we compared the investment in PP&E per megawatt of generating capacity—which depicts the relative cost of building generating plants—with the average system retail rates. High investment in PP&E generally means higher rates. As shown in figure IX.1, TVA has more invested in power plants in relation to their generating capacity than most other utilities in our comparison group, yet its rates are generally lower than the group.[8]

[8]Our analysis excluded nuclear plants that are mothballed and thus provide no capacity while resulting in significant capital costs. Mothballed nuclear plants can be either incomplete or completed plants that have had construction terminated or have been shut down either temporarily or permanently. Under generally accepted accounting principles, these costs are either written off or, if deemed allowable by the applicable regulator, are classified as "regulatory assets" and included in rates through amortization. Inclusion of these "regulatory assets" would have increased the IOUs' investment.

Figure IX.1: Comparison of Investment in PP&E and Retail Rates Among TVA and Neighboring IOUs



Note: Data for TVA are from fiscal year 1996. TVA's average system retail rate represents the average system retail rates for its distributors.

Source: GAO analysis of financial data in 1995 annual reports and Financial Statistics of Major U.S. Investor-Owned Utilities 1995 and Inventory of Power Plants in the United States, Energy Information Administration (EIA), January 1996.

TVA's relatively high investment in utility plant results from its high investment in nuclear plants. As shown in figure IX.1, of the 11 utilities in our comparison group, only Illinova has invested more in PP&E per megawatt of generating capacity than TVA. Figure IX.1 also shows that Illinova's average rate is higher than the average system rates for TVA's distributors. In addition, KU Energy, which had the lowest investment in PP&E per megawatt of generating capacity, also had the lowest average rates. TVA's relationship between its investment in PP&E per megawatt of generating capacity and rates does not follow this pattern. TVA has invested more in assets per megawatt of generating capacity than all but one IOU in our comparison group, but has lower rates than all but three of the IOUs. TVA's low rates have been significantly impacted by its decision to defer substantial costs and cost advantages—discussed later in this appendix—from being a government corporation.

TVA Faces Some Competitive Pressure Today

While TVA's wholesale rates look relatively competitive in the Southeast, we believe TVA's competitive position will be weakened when it begins to recover the $6.3 billion of deferred assets. TVA's vulnerability to wholesale competition, without protection, was recently demonstrated when one of its customers, Bristol Virginia Utilities Board, announced that it will leave the TVA system for Cinergy, Inc. Cinergy offered Bristol firm wholesale power at 2.59 cents per kilowatthour (kWh) for 7 years—40 percent lower than TVA's comparable wholesale rate of 4.3 cents per kWh. According to its General Manager, Bristol will save $70 million over 7 years, and the typical residential customer will save $11 per month. Bristol, which is on the border of TVA's service area, was able to purchase this power because it had given TVA written notice of its intent to cancel its power contract and had received a unique exemption in the Energy Policy Act of 1992, which allows other utilities to transmit (wheel) electricity to Bristol over TVA's power lines. As a result of Bristol's exemption, TVA is required to wheel Cinergy's power to Bristol. While we recognize that Cinergy may have offered this power to Bristol at marginal rates, this is the type of competitive situation that TVA might face regularly if it lost its current protections from competition.

The concerns of TVA industrial customers—which represent approximately 15 percent of its load—about future price increases will put pressure on TVA not to raise rates and thus to continue to defer costs and maintain high debt levels. Unlike residential customers, the larger industrial entities are willing and able to leave a utility's service area to find alternative, cheaper sources of power. Officials from the Tennessee Valley Industrial Committee and Associated Valley Industries, which represent industries that purchase electric power directly from TVA or through TVA's rural or public power distributors, told us that they believe there is room for TVA to lower its firm power rates. They stated that any increase in industrial rates would be unwelcome because they believe TVA's current rates are too high when compared to the firm industrial rates of other utilities. The officials said they would continue to advocate cost control and more favorable firm power rates.

Other Factors Could Negatively Affect TVA

In addition to TVA's high fixed and deferred assets, we believe the concentration of TVA's sales to its five largest distributors and the number of TVA's customers that are already connected to the transmission line of other utilities also contribute to TVA being vulnerable to future competition.

TVA's customer profile may increase competitive pressures. TVA sells electric power at wholesale rates to 160 municipal and cooperative power distributors, the majority of which are relatively small. In fiscal year 1996, over 63 percent of the distributors had a peak demand of less than 110 megawatts. However, five municipal distributors account for over 34 percent of TVA's total sales to distributors (Chattanooga, Knoxville, Memphis, and Nashville, Tennessee, and Huntsville, Alabama). TVA's largest distributor, the City of Memphis, had a peak demand of about 2,943 megawatts in fiscal year 1996—representing approximately 11 percent of TVA's total sales to distributors. Because Memphis is at the edge of TVA's service area, it may be particularly vulnerable to competitive advances of other utilities.

Officials from these large distributors expressed concern that TVA's power contracts offer distributors no flexibility to purchase power from outside sources. The officials discussed a number of possible options that TVA should consider, including shortening the length of its power contracts, giving distributors the freedom to fill some of their requirements from outside sources, or tying its wholesale rates to a market index. The large distributors hope to use their leverage in order to compel TVA to renegotiate their power contracts. In a competitive environment, TVA would likely have to lower the rates of these distributors or run the risk of losing them as customers, which could be financially crippling to TVA.

Another competitive pressure arises because although TVA is exempt from the wheeling provisions of the Energy Policy Act of 1992, 12 of TVA's 160 distributors are already interconnected with other utilities. Therefore, even if other utilities are prevented from using TVA's lines, these distributors could get power from other sources after their contracts with TVA expire. These distributors are scattered around the periphery of TVA's service territory. Some of these distributors are connected to both TVA and other utilities, whereas others are not connected to TVA's transmission network at all. According to one TVA study,[9] 26 percent of the load for distributors on the periphery of TVA's system is served by transmission lines owned by other utilities. This load accounts for approximately 2 percent of TVA's total load. As competition intensifies in the region, TVA could lose distributors to other suppliers using existing and future transmission connections.

Mitigating Factors Reduce Risk of Loss

TVA has a number of factors that mitigate its high fixed and deferred assets. These factors include inherent cost advantages, management actions to cut operating expenses, and an extensive transmission system. Because of these factors, we believe the risk of loss to the federal government is reduced but is still reasonably possible.

Inherent Cost Advantages

According to bond rating agencies, TVA's creditworthiness is based on its links to the federal government rather than on the criteria applied to a stand-alone corporation. As a result, the private lending market has provided TVA with access to billions of dollars of financing at favorable rates. In accordance with section 15d of the TVA Act, TVA's debt issuances explicitly state on the bond prospectus that the bonds are neither legal obligations of, nor guaranteed by, the U.S. government. Nevertheless, TVA's bonds are rated by the major bond rating agencies as if they have an implicit federal guarantee. One of the major bond rating services believes, and we concur, that without the links to the federal government, TVA would have a lower bond rating and higher cost of funds.

TVA also enjoys many advantages as the direct result of being a federal corporation. As a federal government corporation, TVA is exempt from federal and state income taxes and does not pay various local taxes. Therefore, TVA, as a nonprofit entity, does not have to generate the net income that would be needed by an IOU to provide an expected rate of return. However, the TVA Act requires TVA to make payments in lieu of taxes to state and local governments where power operations are conducted. The base amount TVA is required to pay is 5 percent of gross revenues from the sale of power to other than federal agencies during the preceding year—these amounted to about $256 million in fiscal year 1996. In addition, according to TVA, its distributors are required to pay various state and local taxes which amounted to about $125 million, or about 2 percent of the total fiscal year 1995 operating revenues of TVA and the

[9]The Ties That Bind: TVA in a Competitive Electric Market, Palmer Bellevue, a division of Coopers & Lybrand L.L.P., April 1995.

distributors. In comparison, according to the EIA, IOUs pay about 14 percent of operating revenues for taxes. In addition, interest income for TVA's bondholders is generally exempt from state income taxes, which further lowers TVA's costs of funds.

TVA has relatively more hydroelectric power than neighboring utilities. Eleven percent of its power comes from hydroelectric dams built between 1912 (pre-TVA) and 1972—20 to 85 years ago, whereas, on the average, only about 6 percent of the power from other utilities comes from hydroelectric dams. These established hydroelectric projects are relatively inexpensive and have no associated fuel costs. TVA continues to upgrade and improve its hydroelectric plants. TVA has 113 hydro units at 29 conventional dams and the Raccoon Mountain Pumped-Storage facility on the Tennessee River and its tributaries that produce electricity. TVA is refurbishing and upgrading 88 hydro units at 24 hydroelectric dams as part of its Hydro Modernization Program. In addition, TVA also dispatches power from four hydroelectric dams that are owned by a subsidiary of the Aluminum Company of America. Table IX.4 shows the contrast between TVA and other utilities in the percentage of power from different generating sources.

Table IX.4: Percentage of Power Generation From Different Sources for TVA and Other Utilities, 1996

Utility	Coal	Nuclear	Gas	Hydro	Other
TVA	65.0	24.0	0	11.0	0
Other utilities	57.5	24.2	9.7	6.1	2.5

Source: TVA and EIA.

TVA also has a competitive advantage because it purchases low cost hydroelectric power from Southeastern. According to TVA, it satisfies about 2 percent of its annual power needs from the power marketed by Southeastern, which represents about 80 percent of the power marketed by Southeastern from the dams on the Cumberland river. In fiscal year 1996, TVA purchased this power at 0.8 cents per kWh.[10]

Management Actions and Plans to Reduce Costs and Increase Revenues

Recently, TVA has taken a number of steps to reduce its operating and capital expenses and become more competitive. For example, it canceled a number of its nuclear construction projects in the early 1980s and reduced annual operating costs by nearly $800 million, primarily by cutting its workforce in half (from 34,000 in 1988 to 16,000 in 1996) and

[10]See volume I for a discussion of Southeastern's cost advantages that allow it to market low cost power.

refinancing its debt at lower interest rates. Another important step for TVA is the completion of its Watts Bar 1 and restarting of its Browns Ferry 3 nuclear power units, which were major reasons for TVA's increased debt in recent years. In addition, according to TVA, it has internally capped its debt limit at about $28 billion and plans to finance its future capital expenditures from operations.

On July 22, 1997, TVA released a 10-year business plan that identifies actions it plans to take to position its power operations to meet the challenges from the coming restructured marketplace. This plan calls for TVA to (1) increase power rates enough to increase annual revenues by about 5.5 percent ($325 million), (2) take various actions to reduce its total cost of power by about 16 percent by fiscal year 2007, (3) limit annual capital expenditures to $595 million, and (4) reduce debt by about 50 percent from $27.9 billion as of September 30, 1996, to $13.8 billion by fiscal year 2007. To the extent TVA is able to use the cash generated from increasing rates, reducing expenses, and capping future capital expenditures to pay down debt, the risk of loss to the federal government is reduced. In addition to these actions, the plan calls for TVA to change the length of the wholesale power contracts with its distributors from a rolling 10-year term to a rolling 5-year term beginning 5 years after the amendment. However, reducing the length of the wholesale contracts with its distributors could increase the risk of loss to the federal government.

Extensive Transmission System

A major advantage to TVA in a competitive environment will be that TVA owns and operates an extensive transmission system extending into seven states and consisting of 17,000 miles of high voltage lines interconnecting with 16 neighboring utilities at 57 interconnecting points. Even if TVA is forced to allow other utilities to use its power lines to sell power to its customers, TVA will have the right to charge the other utilities a fee for using its transmission lines. During 1996, TVA spent $228 million to expand and improve the reliability of the transmission system, and it projects spending an average of approximately $183 million annually for fiscal years 1997 through 2001 to further improve and upgrade its transmission facilities.

TVA believes it has legal authority to recover stranded costs from customers that may choose to leave the system and will be able to use charges for use of its transmission lines to do so. Various other mechanisms could also be used for the recovery of stranded costs, including fees charged to customers that have or may decide to discontinue purchasing TVA power. However, TVA recognizes that there are legal, political, and commercial uncertainties regarding the possibility of recovering stranded costs.

Comments From the Rural Utilities Service

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

DEPARTMENT OF AGRICULTURE
OFFICE OF THE SECRETARY
WASHINGTON, D.C. 20250

JUL 8

Ms. Linda M. Calbom
Director, Civil Audits
Resources, Community, and
Economic Development Issues
General Accounting Office
441 G Street, N.W.
Washington, D.C. 20548

Dear Ms. Calbom:

We appreciate the opportunity to review and comment on the draft General Accounting Office (GAO) report entitled Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses. We understand this report is for the Chairman of the House Budget Committee and the Chairman of the House Committee on Resources, Subcommittee on Water and Power Resources.

We have the following comments:

See comment 1.

We agree that the overwhelming majority of the Rural Utilities Service (RUS) electric borrowers are financially sound. This was the conclusion of the GAO report completed as recently as April 1997, and reaffirmed by this report. As indicated in both reports, there is a small number of borrowers, less than 2 percent of the total, who, because of the timing of their involvement in electric generating projects (in all cases minority ownership partners with investor-owned utilities in large nuclear generating plants) are experiencing financial difficulties. These projects were initiated during a period 15 to 20 years ago, when changing environmental and nuclear safety regulations, double-digit inflation and double-digit interest rates, resulted in ultra high costs of new plant construction (some as high as 4 times the original estimate) throughout the electric industry. Concurrent with this situation is the fact that projected demand for energy did not materialize.

The financial markets and the electric utility industry have long been aware of the events of this period and the industry has changed as a result. It is important that we remain cognizant of this history, however, as the entire electric utility industry is facing a new environment due to sweeping changes in the legislative and regulatory climate in which it operates. We believe our focus should also be on these changes and their future effects on America's rural electric infrastructure.

AN EQUAL OPPORTUNITY EMPLOYER

Ms. Linda M. Calbom 2

We do foresee some write-offs of debts in the near future because of the 15 to 20 year old investments initially made by borrowers. We take exception, however, to the GAO statement that it is probable that other borrowers, those who are not currently financially stressed, will also require write-offs of their loans. Clearly the past history of power plant investment is not useful in projecting the future in a new competitive, restructured, unbundled, infrastructure.

The April 1997 GAO Audit-Report indicated the majority (98%) of electric borrowers had favorable financial ratios. They are meeting their loan obligations and delivery service to their member owners and contributing to economic infrastructure of their rural communities.

See comment 2.

As additional support for our position, we quote a report from Standard and Poor of April 1995. This special report deals with those RUS-financed generation and transmission borrowers who have received public financial ratings. It states:

> "As competition increases in the electric utility industry, publicly rated generation and transmission rural electric cooperatives (G&Ts) are well positioned to remain viable power suppliers in the future. These G&Ts have demonstrated their ability to compete in a changing environment through proactive management, low power production costs, access to wholesale markets, and minimal capital expenditures for regulatory compliance. S&P believes that the challenge to the G&Ts will be to work with their member systems in continuing to reduce the end user's retail rates through load management, economic development rates, and system efficiency improvements."

As the electric utility industry evolves into the new deregulated, competition driven, customer choice environment, Federal and state legislative and regulatory policies will play the major role in the future risk exposure to the RUS loan portfolio as well as in the continued availability of reasonably priced electric energy in rural areas. We believe that these policies must take into consideration the special challenges facing rural systems that provide electric service in the remote and high cost service areas of rural America. As it has throughout its history, this agency is working closely with its borrowers to ensure that these challenges are recognized and addressed.

See comment 1.

Regarding the method the GAO employs in calculating the financing costs of the RUS electric program, we are somewhat confused . It appears that the GAO applied a long-term average interest rate for Treasury borrowings to the outstanding cumulative debt of RUS. We do not see the relevance of this calculation in determining the costs to the Government of the current lending program. Your report of April 1997 stated the

See comment 3.

Ms. Linda M. Calbom 3

total costs for the Electric Loan Program from 1992 through 1996 were $551.3 million instead of the $4.796 billion calculated in this report. The April report was based on Credit Reform measures and indeed the report goes to some length in describing Credit Reform methods of measuring program costs. It would appear that your latest study implies that Credit Reform does not exist or does not accurately measure program costs.

We disagree with the GAO use of average revenue per kilowatt-hour as an indicator for energy production costs. We believe that there are many variables which have not been addressed in your analysis that could significantly alter any comparison. We would suggest that this material not be included in your current report.

Again, we appreciate the opportunity to comment on this draft report.

Sincerely,

Jill Long Thompson

JILL LONG THOMPSON
Under Secretary
Rural Development

The following are GAO's comments on the Department of Agriculture's letter dated July 8, 1997.

GAO Comments

1. Our April 1997 report presented information on the financial condition of the RUS loan portfolio as of September 30, 1996, and included selected financial statistics and ratios reported by the RUS borrowers. We also noted in that report that "RUS' electricity portfolio faces the possibility of additional financial stress due to increasing competition among the providers of electricity." The current report addresses this issue and assesses the likelihood of future losses to the federal government from its direct and indirect involvement in RUS. For example, we determined that $10.5 billion of the $32.3 billion, or 33 percent, of the total electricity portfolio represented loans to borrowers that are in bankruptcy or otherwise financially stressed. It is probable that the federal government will continue to incur substantial losses from loan write-offs relating to RUS borrowers that are currently bankrupt or financially stressed.

It is also probable that future losses will arise from other RUS borrowers with high production costs based on our analysis that shows that 27 of the 33 viable G&T borrowers had higher production costs than the IOUs in their regions. We believe that current production costs will be a key factor in the ability of RUS G&Ts to compete in a deregulated environment. In fact, RUS officials told us that several borrowers currently considered viable by RUS have already asked RUS to renegotiate or write off their debt because they do not expect to be competitive due to high production costs.

2. We agree that the publicly rated G&Ts are better positioned to remain viable power supply borrowers. However, only 7 of the 55 RUS power supply borrowers are publicly rated by bond agencies. In addition, in May 1995, Moody's Investors Service issued an opinion on the viability of RUS borrowers in their report entitled, Moody's Outlines Risk Profile for Electric Cooperatives. It states:

> "Historically, G&Ts have had a number of structural disadvantages in competing with IOUs, including generally higher rates, transmission constraints, lower equity ratios, and capacity planning problems. Moreover, they also face the need to find new sources of funding to compensate for the reduced availability of guaranteed loans from RUS. We expect that the confluence of factors will result in the deterioration of the overall credit quality of the cooperative industry over the next 5 to 10 years."

3. Discussed in the “Agency Comments and Our Evalution” section of the letter in volume 1.

Comments From Southeastern, Southwestern, and Western

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

Department of Energy
Power Marketing Liaison Office
Washington, DC 20585

JUL 1 1997

Mr. Gene L. Dodaro
Assistant Comptroller General
Accounting and Information Management Division
United States General Accounting Office
Washington, D.C. 20548

Dear Mr. Dodaro:

This letter serves as the written comments of the Southeastern, Southwestern, and Western Area Power Administrations on the General Accounting Office draft report entitled Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses (GAO/AIMD-97-110), dated June 1997. We appreciate the opportunity to comment and suggest technical corrections to the draft report before it is released in final form.

In this letter, we have limited our comments to the most important policy and technical issues raised by the report. In the enclosures, we are providing you with comments and suggestions of a more editorial nature.

NET RECURRING COSTS

See comment 1.

Use of Treasury's Average Outstanding Borrowing Rate to Measure Net Financing Cost is Improper. The three PMAs believe the Treasury's average outstanding borrowing cost is an invalid measure against which to compare PMA average interest rates for purposes of determining net cost. This is because the "portfolio method" assumes that both the PMA interest rate and the Treasury's cost of funds are variable, so the cost difference on any individual investment varies from year to year. This approach is equivalent to refinancing the PMAs' unpaid investment on an annual basis. We are unaware of nonfederal utilities refinancing their long-term debt in this manner. (Some utilities may issue "callable" notes, but the "call" provision is exercised only when it is to the utility borrowers' financial advantage to do so. The three PMAs cannot refinance their unpaid investment at Treasury without Congressional action, as was done recently for the Bonneville Power Administration.)

Our concern may be better explained by an example. A fixed interest rate is assigned to each investment the PMAs' customers are to repay much like a homeowner receives a fixed-rate home mortgage interest rate from a lender. Market interest rates may change in a subsequent year, but the homeowner -- and the PMA -- continue to pay the interest rate in effect at the time the debt was first incurred. To assert that a PMA imposes a net cost to the Treasury in any year when market interest rates have risen above the interest rate on the PMA investment is equivalent to saying that the homeowner imposes a net cost on a lender whenever market rates for home loans rise above the homeowners' fixed mortgage rate. This does not seem reasonable, in our opinion. We believe the use of the "portfolio method" results in a flawed and misleading estimate of the

We believe the use of the "portfolio method" results in a flawed and misleading estimate of the net cost to the Treasury. Because of this disagreement over methodology, the three PMAs do not concur with the draft report's estimates of the magnitude of the net cost.

The PMAs believe a more accurate methodology for determining the magnitude of the financing cost difference is to use the "loan-by-loan methodology" without refinancing. This method compares each investment's interest rate against Treasury's cost of borrowing in the year the investment is placed in service. If there is a difference then a net cost exists, but the amount of unrecovered cost difference remains fixed for each year the investment remains unpaid.

We note that the draft report indicated that GAO staff performed a year-by-year comparison of interest rates for Southwestern's outstanding debt that resulted in a net financing cost that was greater than the one calculated using the "portfolio method". We can not support this conclusion since the GAO analysis assigned a new interest rate to unpaid PMA debt after 30 years because the Treasury currently doesn't issue debt instruments with maturities longer than 30 years, even though some PMA debt does not have to be repaid for up to 50 years. Over this century the Treasury has changed the longest maturity of the debt it issues. Some years the longest maturity on Treasury debt issued has been less than 30 years; in other years, the longest maturity debt issued has been longer than 30 years. However, the maturity of Treasury debt is not based on PMA repayment periods, and Treasury's choices of maturities should not be treated as imposing new financing costs on the PMAs.

The three PMAs suggest using Treasury's interest rate yield curve every year to assign interest rates to PMA debt equal to the yield on Treasury securities of similar maturity. Extrapolating the annual yield curve would provide interest rate proxies for yields on Treasury bonds with maturities of more than 30 years. These proxies should be utilized as the interest rates assigned to PMA debt with repayment periods exceeding 30 years.

See comment 2.

Discussion of PMA Net Financing Costs Should Point Out Corrective Action Taken. The discussion of the origins of the net financing cost to the Treasury should include a discussion of how the DOE guidance on setting interest rates on new investment was modified in 1983 to address the difference in interest rates. As pointed out by GAO in a previous report, unless the law requires otherwise, all new Federal power investments placed in the rate base since that time bear interest equal to the current Federal borrowing rate. This corrected the problem for new investment after 1983.

See comment 1.

Average Revenue per Kilowatt-hour is Overly Simplistic. Although the three PMAs are glad that the GAO draft report found them to be competitive in most instances, we must still object to the use of average revenue per kilowatt-hour (kWh) to compare utilities' competitiveness. We believe the use of average revenue per kWh is overly simplistic, and may mislead the report's readers about the magnitude and causes of the difference in costs between the PMAs and other utilities. The problem is that average revenue per kWh does not take into account the differences in the types of power being sold by different utilities. Examples of different types of power are firm vs. nonfirm, long term vs. short term, and on-peak vs. off-peak. In the electric power markets, these differences result in different prices (and, hence, revenues) for the different types

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of power sold. These differences are not accounted for when using an average revenue figure to compare utilities. A more accurate measure, albeit one that is much more difficult to obtain good data for, is to compare similar products being offered by different utilities.

A related problem with using average revenue per kWh as a measure of a PMAs' competitiveness is that this figure will vary year by year for certain hydropower projects, depending on water conditions. For example, Southwestern's annual cost of power ranges from $0.012 to $0.030 per kWh depending on how much hydropower is available. The draft report's reliance on average revenue per kWh could result in wide variations in a PMAs' competitive position from year to year, which suggests that it is not an accurate measure.

See comment 3.

Balance Needed in Volume I. Volume I discusses key advantages the three PMAs have, but certain offsetting disadvantages of the three PMAs (e.g. paying for the Hoover Dam Visitors' Facility) are left to Volume II. The three PMAs' cost disadvantages, some of which are directed by Congress, include Western having to pay for "aid to irrigation", future replacements costs, payments in lieu of taxes, and, for two Western projects, billions in future irrigation investments that are not even in service. For example, Southwestern estimates that the inclusion of future additions and replacements in their current repayment study result in their rate being 10-15 percent greater than it would otherwise be. These cost disadvantages need exposure in Volume I, as well.

RISK ASSESSMENT OF FUTURE LOSSES

See comment 4.

The Three PMAs Concur in the Report's Finding that They Are Generally Competitively Sound. This finding is based in large part on the three PMAs' experience to date in the emerging competitive power markets and on a comparison of PMA power rates against those of other utilities. We appreciate the report's finding that the PMAs' lower costs are, in part, due to agency management efforts to control expenditures.

See comment 5.

Inclusion of Western's Irrigation Aid in Electricity-Related Activities Is Misleading. Table 3 of Volume I presents the financial involvement of the three PMAs in electricity-related activities. Yet the $7.0 billion amount for direct financial involvement includes $1.6 billion of Western's aid to irrigation obligation, which although a debt to be repaid by power customers, is not truly electricity related.

See comment 1.

Risk of Future Losses by the Three PMAs Is Overstated. Appendix VII discusses the risks of future loss to the federal government associated with six PMA projects/ratesetting systems. For four of the six -- the new investments in Russell, Truman, Mead-Phoenix, and Washoe -- the draft report concludes it is "probable" that the federal government will experience future losses, at least under certain conditions. Except for the Pick-Sloan suballocation, we believe the risk of these projects not recovering all their costs is either "remote" or "reasonably possible", but not "probable" as the GAO draft report states. Our reasoning for each project is discussed below.

See comment 6.

For the four new investments, the draft report's conclusion that the risk of loss is "probable" is

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based on today's market price for power. While the project rate can certainly exceed the market rate at various points in time, the key question is whether this is likely to occur over a facility's entire repayment period. All of these projects still have at least 40 years to be repaid. With the wide fluctuations in energy markets that have occurred over the past 25 years, the three PMAs are reluctant to conclude that projects which are uneconomic today will remain so forever. A number of PMA projects that were first placed in service in the 1950's were uneconomic in their first few years, but now are some of the PMAs lowest-cost facilities.

See comment 7.

Volume I should include a discussion of the mitigating factors for the three PMAs that reduce the probability of loss, just like Volume I's discussion of mitigating factors for Bonneville Power Administration and Tennessee Valley Authority. For example, the discussion of Western's Transformation process in Volume II should be brought up to Volume I and expanded. Compared to earlier projections of expenses, Western's management actions have reduced expenditures by 27 percent, leading to rate stability and some rate reductions for Western's projects. Also, the reference on page 48 of Volume I relating to BPA's expectation that rising natural gas prices will improve BPAs' competitive position can be extended to the three PMAs' positions, as well. These are significant actions compared to the risks discussed below, and deserve greater attention in order for Volume I to be balanced.

Now on p. 29.

The following comments are provided about each of the six projects/ratesetting systems of the three PMAs identified in the draft GAO report.

See comment 8.

Richard B. Russell Project. The draft GAO report concludes that financial risk to the federal government is "probable" if the pump-back units never operate as intended. Hence, the risk rating is conditional on unit operation. According to Southeastern, the unconditional risk of loss at this project is less than "probable" because the pump-back features of the project are expected to become operational and the rate for power from this system will still be competitive after these units operate. Since Southeastern and the Army Corps of Engineers believe the probability of unit operation is better than 50 percent, the probability of financial loss to the government must be less than 50 percent, making the risk no worse than "reasonably possible."

See comment 9.

Harry S. Truman Project. The situation for the Truman project is somewhat similar to that of the Russell Project. Contrary to the draft report's assumption, Southwestern and the Army Corps of Engineers expect this project's pumpback units to operate. The risk of the federal government losing any money in this eventuality is "remote". In addition, in the unlikely event that the pumpback units never operate, Southwestern would be capable of absorbing the full cost allocated to power of this project and still remain competitive.

See comment 10.

Central Valley Project. First, Western takes issue with the draft report's reference to a "loss" of $24 million for the CVP during FY 1996. Inclusion of this statement implies that the CVP is having difficulty meeting its repayment obligations. It would be incorrect to infer this. While the CVP financial statement shows that net revenues were deficit by $24 million in FY 1996, this "loss" is due to the timing of the Revenue Adjustment Clause adjustments, and the inclusion of depreciation as a cost. The CVP Final 1996

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Power Repayment Study shows that the project has no capitalized deficit at the end of FY 1996 and the power investment is 60 percent repaid.

Second, the draft report cites the Central Valley Project Improvement Act (CVPIA) as impacting the availability of water for power generation and reducing power revenues. We understand that initial studies based on the draft Environmental Impact Statement on the CVPIA indicate an impact on power production of less than 2 percent. Any power lost due to a decrease in generation of this magnitude can be replaced through purchases, if necessary, while still keeping the CVP rate competitive. Hence, repayment can proceed, as planned. Furthermore, Western staff do not believe that a reallocation of CVP costs due to the CVPIA will result in a major increase in power's cost allocation; power's costs could, in fact, decrease.

Finally, references to CVP power being "above market" are comparing CVP's long-term power rate against short-term, spot prices that fall below the CVP rate during certain time periods, particularly when BPA is "spilling water". On average, the current market rate for a 10-year purchase power contract is $0.02/kWh. The market rate for full requirements service, which is the service available from the CVP, is even higher. A formal rate adjustment process is underway to adjust CVP rates to the $0.02/kWh range by October 1, 1997, which will strengthen the competitiveness of CVP power in the long-term market. The CVP and BPA are both marketing power in California, so it is difficult for us to understand why the CVP should be classified as an "uncertain" risk when BPA's near-term risk is classified as "remote".

In our opinion, the risk of a loss to the federal government from the CVP is "remote" at this point in time, although upcoming decisions on Trinity River flows may increase the risk to "reasonably possible."

See comment 11.

Pick-Sloan Missouri Basin Program. Here, Western concurs with the draft report's conclusion that it is "probable" that principal and interest for the suballocated investment will not be recovered absent legislation. Nevertheless, it appears that not collecting these costs was Congress' intention so, in this case, the "probable" outcome is what the law desired. In addition, the report's use of accrual accounting is in conflict with the congressional requirement to allocate Pick-Sloan's costs according to the project's ultimate development.

See comment 12.

Mead-Phoenix Transmission Line. This investment is in the second year of its 35-year repayment period. It is true that the first year's financial results were disappointing, but many changes can occur before this investment becomes "due". It is very premature to conclude on the basis of such preliminary evidence that financial loss to the Treasury is "probable". Western has already initiated a rate adjustment process for the Pacific NW-SW Intertie Project (of which the Mead-Phoenix Project is one part). As part of this effort, Western is discussing the possibility of melding the Mead-Phoenix transmission rate with the rate for the older Intertie system, thereby increasing project revenue and providing greater certainty of Mead-Phoenix repayment.

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See comment 13.

Washoe Project. Western notes that power-related costs reallocated to fish and wildlife purposes are, by law, nonreimbursable. Washoe power is used to offset fish and wildlife power purchases. Enactment of new legislation would be necessary to reverse this situation. Even so, the probability of loss to the federal government is judged to be "remote" by Western staff because the agency is proposing to blend Washoe power with CVP power after 2004 to ensure sale of Washoe power and recovery of Washoe's power repayment obligations.

See comment 14.

We recommend that Volume I contain an expanded version of Table 3 that breaks out GAO's assessment of risk for future loss on each agency's financial involvement as "remote," "reasonably possible," and "probable." A table would allow the reader to instantly see the magnitude of potential loss. We created the following table based on what the three PMAs assess as their own likelihood of loss, and used the GAO draft report for the other entities' risk assessment of future loss.

Assessment of Risk for Future Loss
on
$84 Billion in Financial Involvement
(Dollars in Billions)

	DIRECT				INDIRECT			
Entity	Probable	Reasonably Possible	Remote	TOTAL	Probable	Reasonably Possible	Remote	TOTAL
RUS	$10.5	$11.7	$10.1	$32.3				
SEPA			$1.5	$1.5				
SWPA			$0.7	$0.7				
WAPA			$4.8	$4.8			$0.2	$0.2
BPA			$10.1	$10.1			$7.1	$7.1
TVA			$3.8	$3.8			$24.1	$24.1
TOTAL	**$10.5**	**$11.7**	**$31.0**	**$53.2**				**$31.4**
							GRAND TOTAL	**$84.6**

Note:
GAO rated BPA's $17.20 billion risk of loss as "Reasonably Possible" after FY 2001.
GAO rated TVA's $27.9 billion risk of loss as"Reasonably Possible" if TVA should lose its protected market position.
GAO has rated WAPA's $0.5 billion of suballocated Pick-Sloan irrigation investment as having a "Probable" risk of loss under current law. WAPA concurs. This amount is not included in the above table.

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See comment 15.
Now on p. 4.

We are pleased to note that the document makes references to the fact that the federal agencies "were generally following applicable laws and regulations regarding recovery of costs." (Page 6 of the draft report.) It is our suggestion that the logical extension of this point be explicitly made, as well; namely, that legislation must be enacted if Congress decides that certain of these other costs must be fully recovered.

Thank you again for the opportunity to provide written comments on the draft report.

Sincerely,

Joel K. Bladow

Joel K. Bladow
Assistant Administrator

Enclosures

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The following are GAO's comments on the three PMAs' letter dated July 1, 1997.

GAO Comments

1. Discussed in the "Agency Comments and Our Evaluation" section in the letter in volume 1.

2. We agree. We have added to volume 1 of our report a discussion of the 1983 change in guidance on setting interest rates for PMA-appropriated debt.

3. We have appropriately included all salient points relative to the three PMAs' net cost and risk to the federal government in both volume 1 and appendix VII of volume 2. Additionally, we disagree with the three PMAs' characterization of certain costs as "disadvantages." For example, we do not agree that including future replacement costs in Southwestern's power rates have increased its rates by 10 to 15 percent. The revenues generated by including these costs in current rates have actually been applied to current year appropriations or other appropriated debt. As a result, Southwestern has been able to repay most of its recent higher interest rate debt. Thus, its weighted average interest rate was 2.9 percent, considerably lower than Southeastern's (4.4 percent) and Western's (6.0 percent). Southwestern's repayment of higher rate debt has enabled it to minimize interest expense and electricity rates for its customers. Rather than viewing this as a "cost disadvantage" to Southwestern or its customers, we believe Southwestern has managed its appropriated debt using sound business principles and has minimized the interest expense that must be recovered through rates.

Regarding the requirement to repay irrigation debt, the three PMAs overstate the impact of this requirement on Western. Our review of Western's fiscal year 1996 financial statements shows that, as of September 30, 1996, the *cumulative total* amount of irrigation investment repaid by Western was just over $33 million. A cumulative total repayment of that amount does not represent a significant cost disadvantage for an entity that has had gross annual operating revenues averaging more than $775 million over the 5-year period from 1992 through 1996. We agree that to the extent that power revenues are actually used to repay irrigation investment it is a disadvantage to power customers; however, we do not agree that the impact has been significant enough to be highlighted in volume 1 of the report.

The three PMAS also overstate the likely impact of Western's potential repayment of future irrigation investments. The billions of dollars that the three PMAS refer to are not costs that have been incurred, and it is questionable whether they will ever be incurred. To the extent that these planned future costs are included in Western's current rates, any resulting revenue would actually be applied to other appropriated debt. Until these future irrigation costs are incurred and repaid, or funds are set aside for their future repayment, they do not represent a disadvantage to Western or its customers.

Regarding payments made in lieu of taxes, we acknowledge in appendix VII that the Boulder Canyon Project, marketed by Western, makes annual payments in lieu of taxes to the states of Arizona and Nevada. In 1995, the payments totaled about $600,000, or 1.2 percent of the Boulder Canyon Project's operating revenue. In contrast, according to the Energy Information Administration, IOUS paid taxes averaging about 14 percent of operating revenues in 1995. Moreover, despite raising the issue of payments in lieu of taxes, the three PMAS have been unable to substantiate that they or the operating agencies have made any payments in lieu of taxes other than those to the states of Arizona and Nevada.

4. We concur with the three PMAS' comment that the three PMAS' costs, and resultant power rates, are generally lower than their competitors. In our report, we used average revenue per kilowatthour (kWh) to demonstrate this favorable comparison.

5. We disagree. It is appropriate to include the irrigation debt in our discussion of the federal government's financial involvement in electricity-related activities because it is to be recovered primarily by power revenues.

6. We do not agree that the investments in Russell, Truman, and Washoe are "new investments." Construction on Russell began in 1976, the four operating units came on line in 1986, and the four nonoperational units were completed in 1992. The nonoperational units at Truman were specifically deferred from inclusion in rates as part of FERC's approval of Southwestern's 1989 power rates. Power sales at Washoe began in 1988. Thus, Russell, Truman, and Washoe have a history of operating and financial problems. We see no evidence provided by the three PMAS that this troubled past will not continue. We concur that Mead-Phoenix, which began operation in April 1996, can be considered a "new investment." However, the results we report for Mead-Phoenix's first 9 months of

operation, coupled with the lack of customers for Western's share of capacity, demonstrate that this investment meets the criteria for a probable future loss to the federal government.

7. In volume 1, we conclude that the three PMAS are competitively sound overall, except for a few projects or rate-setting systems that, taken as a whole, make risk of some loss to the federal government probable. We then discuss these projects in detail in appendix VII. Because we assess the three PMAS as competitively sound overall, a discussion of mitigating factors in volume 1 is not needed. The mitigating factors we identified for each of the three PMAS are discussed in appendix VII.

8. We agree that the risk of loss at Russell is conditional. As stated in appendix VII, if the nonoperational pumping units do not operate commercially, it is probable that the federal government will lose its entire $518 million investment. In addition, we state that, if full deployment of the pumping units continues to be delayed, the risk of loss to the federal government is reasonably possible. Also, if the nonoperational pumping units are allowed to operate commercially and placed into rates in the near future, the Georgia-Alabama-South Carolina system, of which Russell is a part, should be able to remain competitive. Under this scenario, the risk of loss to the federal government is remote. We have added language to appendix VII to clarify the conditional assessment of risk at Russell.

9. The statement that the "Army Corps of Engineers expect this project's pumpback units to operate" is contrary to what the Corps of Engineers told us. In addition, the fact that the costs associated with the nonoperational pumping units have been deferred from Southwestern's rates since 1989 suggests that the outcome is very uncertain. Moreover, we disagree that Southwestern would be able to absorb the full cost allocated to power and still remain competitive even if the pumping units do not operate. Even if Southwestern has the financial capability to absorb these costs, this assertion by Southwestern overlooks the policy guidance contained in DOE Order RA6120.2, which indicates that if the nonoperational units are not put into commercial service, the power customers will not be required to repay the investment. Therefore, if the pumping units remain nonoperational, it is irrelevant whether Southwestern could afford to absorb the costs. However, we have added language to appendix VII to clarify that if the nonoperational units at Truman do operate commercially and are placed into rates, the risk of loss to the federal government is remote.

10. We correctly stated in our draft report that the Central Valley Project (CVP) incurred a net loss of $24 million in fiscal year 1996, as evidenced by the “Net Deficit” of over $24 million shown for CVP in Western’s audited financial statements for that year. Also, we do not agree with the three PMAS’ inference that depreciation should not be considered an expense. Although a noncash expense, depreciation allocates the costs of fixed assets over their useful lives. However, we have added a statement to appendix VII that CVP was able to meet its cash flow requirements in fiscal year 1996.

We believe that the three PMAS have misread our discussion of the potential impact of the Central Valley Project Improvement Act (CVPIA) on CVP. We stated that CVPIA emphasizes the need to safeguard fish and wildlife and, as a result, less water *may* be available for irrigation, power generation, and other purposes. We go on to state that to the extent that the act’s implementation reduces power revenues, the uncertainty over the repayment of the federal government’s investment in CVP’s hydropower facilities increases. We did not attempt to predict the act’s ultimate impact but did describe how the act increases the uncertainty surrounding CVP. Assessing and describing such uncertainty is appropriate when assessing the federal government’s risk of future financial losses.

Considering and discussing prices, long-term and short-term, is appropriate in a competitive environment. In our opinion, the actions taken by Western to respond to competition (that is, decreasing CVP’s rates by 26 percent in 1996 and planning to further reduce rates by exercising escape clauses in purchase power contracts), which our draft report discusses, support this belief. Regarding the three PMAS’ comment that they could not fully understand why we describe the situation at CVP as “uncertain” while describing BPA’s near-term risk as “remote,” the primary difference is that BPA has contracts in place that mitigate the federal government’s risk of future financial losses at BPA for the next few years. Thus, the risk at BPA is remote in the near term.

We have added language to appendix VII regarding the potential reduction in Trinity River water flows to CVP and the impact on the federal government’s risk of future financial losses at CVP.

11. The scope of our work did not include reporting on congressional intent regarding the ultimate repayment of the suballocated irrigation investment.

12. We agree that this investment is early in its repayment period and that financial results may change. However, since project expenses have totalled nearly $7.3 million to date, compared to only $71,319 in revenues, it will be very difficult to achieve the dramatic financial improvement necessary to make the project viable. Because of the lack of demand for power from the line, it appears unlikely that Western will be able to successfully market its entire transmission capacity and recover all relevant costs. As we report, Western officials are discussing blending the line's rate with the rate for the older Intertie system, which they believe will increase project revenue and provide greater certainty of Mead-Phoenix repayment. However, requiring the Intertie to absorb the Mead-Phoenix losses would negatively impact the financial condition of the Intertie. We believe our characterization of the situation as a probable loss if the consolidation under consideration cannot be successfully implemented is correct. In addition, we have added language to appendix VII clarifying our opinion that even if the consolidation can be completed, there is no indication that the demand for power from the line will increase or that Western will be able to successfully market its transmission capacity. Therefore, under this scenario there is a reasonably possible risk of future loss to the federal government.

13. We agree with the three PMAs' statement that proposals by Western to blend Washoe's power with CVP after 2004 could change the risk related to Washoe. However, blending Washoe's high-cost power in with the CVP system would compound the financial difficulties facing CVP that we discuss in appendix VII. We believe that we are correct in concluding that as a stand-alone rate-setting system, Washoe presents a probable risk of loss of the entire federal investment, including deferred payments, of $13 million. In addition, we have added language to appendix VII clarifying that even if the consolidation can be completed, the risk to the federal government of future financial losses from Washoe is reasonably possible, since CVP is itself facing financial difficulties.

14. The unique circumstances of the six entities make it unfeasible to portray this complex information in tabular form. The three PMAs' proposed table gives a distorted picture of the magnitude of the risk by entity. Additionally, the three PMAs may have misunderstood our assessments of risk. We did not conclude that each problematic system represents a probable loss to the federal government. Rather, we concluded that for the three PMAs as a whole, the risk to the federal government of some future financial loss is probable. We added language

to appendix VII clarifying the overall risk to the federal government for the three PMAs and for each of the specific problematic projects.

15. Although determining the extent to which congressional action would be required for the PMAs to recover these costs was beyond the scope of our review, we do not believe that specific legislation would be necessary in order for all of the categories of unrecovered costs to be recovered. For example, the PMAs could recover the full costs associated with Civil Service Retirement System (CSRS) pensions and postretirement health benefits by including these costs in rates and depositing amounts recovered, like many other PMA ratepayer collections, into the General Fund of the Treasury. This would allow the revenue to be available to the Congress to appropriate into the Fund to cover the full cost of CSRS pensions and postretirement health benefits.

Comments From the Bonneville Power Administration

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

Department of Energy

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

EXECUTIVE OFFICE

June 27, 1997

In reply refer to: LF-7

Mr. Gene Dodaro
Assistant Comptroller General
Accounting and Information Management Division
United States General Accounting Office
Washington, DC 20548

Dear Mr. Dodaro:

Thank you for furnishing us with a copy of a Draft Report entitled "Federal Electricity Activities--The Federal Government's Net Cost and Potential for Future Losses" (GAO/AIMD 97-110), dated June 1997 (Draft Report). Your staff has been very accommodating in meeting with the Administrator and staff of the Bonneville Power Administration (Bonneville) to discuss the draft. You have offered us an opportunity to comment on the Draft Report and we thank you for that opportunity. This letter addresses our chief concerns with the Draft Report.

See comment 1.

- The Draft Report overstates the historical cost to the Government of operating Bonneville by assuming implicitly that historically assigned market-approximating interest rates Bonneville pays to the Treasury are now insufficient because interest rates have increased in the past fifty years. By analogy, the interest rates on Bonneville's various 'mortgages' were set by reference to market-priced Treasury obligations *at the time the decisions to construct were made*, not by subsequent interest rates as in the case of a variable or floating interest mortgage. Not only has Bonneville paid the original 'mortgage' in full on valuable investments like Grand Coulee and Bonneville Dams, it has done so to the enduring benefit of the mortgage holder, the Government, which retains ownership of the assets.

See comments 2 and 3.

- The Draft Report diminishes the financial implications of the public benefits Bonneville shoulders under law, their costs, and their contribution to Bonneville's risk of underrecovering its payments to the Treasury. In particular, the Draft Report does not adequately emphasize the fact that Bonneville's fish costs, which are controlled by Congress, are also Bonneville's greatest financial exposure apart from market prices.

See comment 1.

- The Draft Report, while concluding properly that it is "reasonably possible" that the Government will incur a loss from Bonneville's operations, fails to describe the limited, transitional nature of the risk, which is confined to approximately the ten years after 2001. After that period, Bonneville's costs and the price of its wholesale power should be well below market, and the risk to the Government remote , as it is in the period 1997-2001.

1. The Draft Report Substantially Overstates the Government's Net Recurring Expense From Bonneville's Operations by Using an Inappropriate Treasury Cost of Funds to Measure such Expense.

See comment 1.

The Draft Report indicates that in the period fiscal year 1992 through 1996, the Government indirectly contributed an annual average of approximately $398 million in assistance to Bonneville. By far the greatest portion of this amount, $377 million, is asserted to be imbedded interest support on $7.1 billion in outstanding Federal investments in the Federal Columbia River Power System (FCRPS). The Draft Report measures this benefit as the difference between (i) the interest Bonneville paid on the return of the investments at an imbedded interest rate of 3.5 percent, and (ii) the interest that would have been paid at a 9 percent interest rate, which is a composite of currently outstanding long-term debt of the U.S. Treasury.[1] Bonneville disagrees strongly with the Draft Report's approach in this regard.

(a) The Interest Charges Bonneville Pays on the Appropriated Debt Were Determined Years Ago Using Market-Approximating Long-Term Interest Rates at the Time Congress Decided to Make the Related Investments.

See comment 1.

The Draft Report's conclusion disregards the fact that Bonneville's appropriated investment interest payments are market-approximating long-term rates *prevailing at the time construction of each of the related facilities was initiated or authorized to be initiated.* Many of these investments were made years ago, as long ago as 1942,[2] during periods of very low long-term interest rates. In contrast, the composite of Treasury bonds used in the Draft Report is an average of all outstanding long-term Treasury bonds, most of which were issued in relatively high interest markets well after many FCRPS investments' interest rates were assigned. By analogy, a thirty year mortgage entered into in 1967 during a period of low interest rates would not result in a cost to the lender simply because interest rates increased generally in the intervening years. While comparing existing outstanding loans against existing investments may provide some information about loan performance, this approach is not useful in assessing the terms and conditions of the loan at the time it was made. The Draft Report's approach simply does not reflect the cost of capital at the time when the funds were budgeted or authorized by Congress.

See comment 1.

Whether the Government incurred a net cost of financing should be determined on the basis of an assessment of each loan incrementally, as a commercial lender would do. This incremental assessment would focus on both existing economic conditions and future cash flows. The terms and conditions of each loan are established at the time the loan is made and to the extent that they

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[1] The 9 percent rate is derived by the General Accounting Office from "Table 1, Monthly Statement of the Public Debt of the United States, September 30, 1996." It represents the fiscal year 1996 average interest rate on only Treasury long-term bonds, meaning those with original maturities of 10 years or longer.

[2] The Draft Report analyzes repayments Bonneville made in fiscal year 1992, which would include certain investments with very long amortization periods. The repayment period for FCRPS appropriated investments is the expected useful life of the related facility, not to exceed 50 years.

reflect information available at that time determines whether a future net cost will be incurred. Moreover, in initiating the loans to Bonneville, Congress assessed whether the total returns to the Government would exceed the costs of the original investments. Returns that Congress took into account included the benefits of economic development, increased tax receipts, federal policy objectives such as promoting public power, as well as the potential for future repayment of the power portion of the investment in the FCRPS. Most of these benefits would be produced over the economic lives of the projects, which for the FCRPS hydroelectric projects are much longer than their repayment periods. In addition, Congress required that Bonneville provide assistance to irrigators within the Region by repaying to the Treasury $800 million in federal investment incurred in building reclamation facilities.[3]

(b) The Draft Report Uses Only Long-Term Treasury Debt to Gauge Treasury's Cost of Funds, Thereby Inflating Treasury's True Cost of Funds and, Therefore, the Net Cost to the Government of Bonneville's Operations.

See comment 4.

The Draft Report uses 9 percent as the basis for Treasury's cost of capital, which is compared to the weighted average interest rate of Bonneville's outstanding appropriations at the end of fiscal year 1996. By the Department of Treasury's own assessment, the 9 percent rate "neither reflects current Treasury borrowing costs nor the rates at which Treasury lends to agencies." Letter of Fred A. Adams, Associate Director of Market Finance to Steve Dunne, Bonneville Power Administration, dated June 25, 1997. (A copy of the letter is enclosed.)

See comment 1.

Implicit in the Draft Report's use of the measure is an assumption that Treasury matches the lives of assets with the terms of specific liabilities, here the appropriated investments in the FCRPS. This assumption is wrong. Treasury does not rely heavily on long-term debt to finance physical assets. Rather, it manages debt on an aggregate basis to minimize interest expense by issuing debt of varying maturities through bonds, notes and bills without regard to asset lives. *Id.* Any doubt about this conclusion is laid to rest by reference to the comparatively small amount of long-term debt issued by the Treasury relative to the amount of assets of the Government. Outstanding long-term debt represents only $543 billion of the $3,418 billion of outstanding interest-bearing Treasury debt. According to the President's budget for fiscal year 1998, the Government's total physical assets *were more than $1.7 trillion* in fiscal year 1996.

See comment 5.

Thus, it is the Treasury's *portfolio* of total debt that represents its average cost of debt, not selected debt instruments such as those with maturities of 10 years or longer. Therefore, a better measure of the cost of funds to the Treasury would be 6.7 percent, *i.e.*, the average interest rate associated with the $3,418 billion in the total outstanding Treasury debt.[4] Using a 6.7 percent Treasury cost of funds would reduce the Draft Report's measure of the net recurring cost to the

[3] Based on Bonneville's last rate case, the present value of these assistance payments is approximately $195 million.

[4] As suggested above, Bonneville believes there is little net cost to the Government of the appropriated investments in the FCRPS.

Government of Bonneville's appropriated investment by $154 million per year on average in the period fiscal years 1992-1996 (down from the Draft Report's estimate of $377 million per year).

See comment 1.

Another inherent weakness in the Draft Report's use of the 9 percent weighted average long-term interest rate is that there will not necessarily be a high degree of correlation between the repayment interest rates on appropriations for the FCRPS prior to 1974 and the long-term borrowing of the Treasury over the same period. By using the weighted average interest rate of 9 percent to analyze Bonneville's net cost to the Government, the Draft Report assumes that the borrowing pattern for the FCRPS is the same as that of the Government as a whole. This assumption can be demonstrated to be false using a yield curve based on historical interest rates developed by the Office of Management and Budget (OMB) during the Bush Administration, showing that the weighted average interest rate of federal borrowing corresponding to the FCRPS's appropriations was about 7 percent. The portfolios of outstanding long-term Treasury bonds and the FCRPS appropriations are fundamentally different.

(c) If One Were to Measure the Net Costs by Applying Recently Enacted Interest Rate Assignment Practice, the Net Recurring Cost Identified in the Draft Report Would be Substantially Reduced.

See comment 1.

Congress recently endorsed a measure of the Treasury's cost of funds in the 1996 Bonneville Appropriation Refinancing legislation that reset Bonneville's appropriated investment repayment responsibility. 16 U.S.C. 838l. By applying these 1996 statutory changes to Bonneville's past appropriations repayments, it becomes clear that the methodology used in the Draft Report seriously overstates the net cost to the Government of Bonneville's operations. As of fiscal year 1997, new FCRPS investments will be assigned long-term interest rates as of the dates that the related asset is placed in service. Formerly, interest rates were assigned at the long-term rates in effect *at the time construction of the related asset commenced or was authorized*, so that in some cases assigned interest rates relate back to those in effect up to ten years or more prior to the date the related asset was placed in service.[5] Bonneville calculates that the interest rate on the appropriated investments under this approach would have been approximately 7.0 percent, still substantially below the 9.0 percent interest rate used in the Draft Report. In effect, this was the approach used by OMB in its evaluation of FCRPS appropriated interest rates, described immediately above. Using a 7.0 percent Treasury cost of funds would reduce the Draft Report's measure of the net recurring cost to the Government of Bonneville's appropriated investment by $137 million per year on average in the period fiscal years 1992-1996 (down from the Draft Report's estimate of $377 million per year). Again, however, even this measure is flawed because by analogy it presumes that a net recurring expense occurs when a mortgage holder does not unilaterally and retroactively amend the terms of the mortgage.

See comment 6.

[5] The relation-back nature of long-term FCRPS interest rate assignment cuts both ways. Construction of some assets was commenced in high-interest environments, but the assets were placed in service in lower interest rate environments. Nonetheless, the applicable interest rate is the higher rate.

5

(d) The Draft Report is Internally Inconsistent in its Measure of Treasury's Cost of Funds.

There is an internal conflict within the Draft Report. While using an interest rate of 9.0 percent to determine Bonneville's net cost to the Government of the appropriated FCRPS investments, the Draft Report elsewhere implies that a 6.87 percent interest rate is a sound measure for purposes of determining the net cost to the Government of lending funds to the Tennessee Valley Authority (TVA). Both measures of the Treasury's cost of funds cannot be correct. As with Bonneville's appropriated debt, TVA's appropriated debt has been in existence for years, in fact it has been outstanding for 40 years or more; therefore, the costs to the Treasury of carrying the TVA debt should be equal to the costs of carrying the FCRPS repayments. Yet, the Draft Report concludes that TVA is fully recovering the Treasury's cost of financing, while Bonneville, at least with respect to the FCRPS appropriated investments, is not.[6] In view of the prior discussion, it is interesting to note that this 6.87 percent measure of the cost of funds to Treasury is based on long- and *short-term* marketable Treasury securities, as opposed to the 9 percent cost of funds, which is weighted average interest rates on long-term Treasury securities.

(e) The Draft Report Hints that Bonneville Has an Imbedded Interest Rate Advantage that Congress Has Ignored.

See comment 1.

The Draft Report does not adequately address recent Congressional action relating to Bonneville's repayment of the appropriated investment in the FCRPS. The Omnibus Consolidated Rescissions and Appropriations Act of 1996 includes a detailed provision, the stated purpose of which is to resolve permanently the repayment subsidy criticisms that have been leveled at the interest rates Bonneville pays for the appropriated investment in the FCRPS. 16 U.S.C. 838l; Pub. L. 104-34; 110 Stat. 1321-350. This provision, the Bonneville Power Administration Appropriation Refinancing law, requires Bonneville to pay $100 million more in net present value to the Treasury for the FCRPS investments. More specifically, the law reset the principal amount of the appropriated investment at the net present value of the former stream of principal and interest, as of September 30, 1996, plus $100 million.[7] The law also re-established the interest rate Bonneville pays on the appropriated investments at the discount rate used to

See comment 7.

[6] In a similar vein, the Draft Report concludes that when Bonneville issues *bonds* to the Treasury, there is no net cost to the Government even though the average interest rate on Bonneville's bonds is less than 9.0 percent. Indeed, a better analysis would show that interest rates on Bonneville's bonds *exceed* Treasury interest rates at comparable maturities at the time the bonds are issued. This markup is a true net cash flow benefit to the Government. Since Bonneville began issuing bonds to the Treasury after the 1974 Federal Columbia River Transmission System Act, Bonneville pays and has paid a markup on such bonds of roughly 60-100 basis points over Treasury's borrowing rate. As of the end of fiscal year 1996, Bonneville had outstanding approximately $2.456 billion in bonds to the Treasury. The Draft Report does not net this benefit of approximately $15 million per year in determining the net cost of Bonneville's operations.

See comment 1.

[7] The Draft Report also inappropriately describes the effect that the $100 million net present value increase has on Bonneville's future payments on the appropriated investment in the FCRPS. The report mentions the refinancing, but considers that, under the refinancing, "the net present value of future financing costs of the federal government will also remain unchanged." In fact the net present value increase *will* reduce on a going forward basis any net cost to the Government of Bonneville's operations.

See comment 1.

See comment 2.

Now on pp. 24 and 25.

See comment 8.

See comment 9.

calculate the net present value. As a result, the average weighted interest rate on FCRPS interest bearing appropriated investments is now 7.1 percent, up from 3.4 percent, and the principal amount of the appropriated investment declined from $6.7 billion to $4.1 billion.[8] More importantly, the law also provides the ratepayers of Bonneville with a contract covenant that Bonneville will not set rates on the basis of interest rates or principal amounts on the refinanced investments other than as reset by the law. The point here is that the Draft Report appears to backtrack on the essence of the Appropriations Refinancing law, that is, to resolve finally the interest rate issue, by raising once again the specter of subsidized interest on the FCRPS investments.[9]

2. The Draft Report Does Not Take Into Consideration "Public Benefits" provided by the Power Marketing Functions.

While the Draft Report takes pains to point ways in which the low cost of Federal power is the result of advantages investor-owned utilities do not have, the Draft Report underplays the public obligations shouldered by the power marketing administrations. Vol. I, page 41. This perspective ignores the implicit financial costs to the Federal power marketing functions, and in particular to Bonneville, that arise from a number of constraints and obligations that the power marketing functions are required *by law* to bear. In the discussion of the potential for future losses to the Government, Bonneville believes that a more objective description of its financial position would note that many of Bonneville's costs arise because of duties that are placed on it by law, such as fish and wildlife restoration and conservation, and to a great extent they define the risk of financial loss for the Government.

Some of the public benefits Bonneville provides, such as its obligation to protect, mitigate and enhance fish and wildlife, are beyond the responsibilities private sector utilities may bear, for example under FERC hydroelectric licenses, and are much more strongly emphasized and result in comparatively greater costs than would otherwise be the case. Bonneville estimates that in terms of foregone revenues and increased expense its cost for fish protection alone will be approximately $435 million per year on average in the five years ending fiscal year 2001.[10]

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[8] Bonneville disagrees somewhat with the Draft Report's calculation of the effects of the Appropriations Refinancing law on the appropriated investments. The Draft Report cites that the weighted average interest rate increased from 3.5 percent to 7.1 percent, and that the principal amount declined from $6.85 billion to $4.6 billion.

[9] The Draft Report appears to give disparate treatment to legislation in 1959 affecting TVA's then-outstanding repayment obligation to the Treasury, Pub. L. 86-137, and the effects of the 1996 Bonneville Appropriations Refinancing Act. With respect to the TVA legislation, Congress in effect provided that TVA was no longer responsible to repay the Treasury a substantial portion of the principal amount of its then-outstanding appropriated repayment obligation by treating that amount as equity. Thus, the effect of that Act was to reduce the imbedded returns to the Treasury. The Draft Report ignores this change in TVA's imbedded returns to the Treasury. By contrast, the Bonneville legislation *increases* the imbedded returns to the Treasury to quell permanently the imbedded interest cost criticisms leveled at FCRPS repayments. Given this comparison, Bonneville is left to wonder on what basis the Draft Report determines whether an imbedded rate of return is ignored or counted.

[10] There is potential for substantially higher costs should Congress reauthorize certain FCRPS hydroelectric projects to be drawn down or removed. This could reduce Bonneville's revenues and, depending on how past and future

See comment 2.

Others of Bonneville's public responsibilities are unique in kind. For instance, Bonneville is required to extend the benefits of comparatively low cost FCRPS power to residential and small farm consumers of utilities in the Region at a cost of approximately $2.8 billion since 1981. Still others of Bonneville's duties relieve the Government of obligations it would otherwise pay. For example, Bonneville is charged with returning roughly $800 million (the net present of which is roughly $195 million) to the U.S. Treasury for irrigation investments that are beyond the ability of the users thereof to pay.

3. The Draft Report Fails to Characterize Accurately the Transitional Nature of the Risk of Loss to the Government Arising From Bonneville's Operations.

See comment 10.

The Draft Report concludes that the risk of loss to the Government in the future with respect to Bonneville's operations after 2001 is "reasonably possible," which by inference is defined to be a probability of between 5 and 50 percent. Bonneville agrees with this risk assessment but only for the ten year period after 2001. Thereafter, Bonneville expects that its cost of power will be substantially below market prices.

See comment 10.

Bonneville has few obligations to deliver power on a fixed price or cost-recovery basis in effect after 2001. With the development of open wholesale and, possibly, retail, electric power markets, captive customer bases will become anachronistic. Absent implementation of a proposal that would recover Bonneville's costs if and when its costs exceed market prices (as is proposed to some degree by the Comprehensive Review described below), if Bonneville's costs exceed market prices, Bonneville will be forced to sell its power at prices determined largely by the marketplace. Thus, Bonneville's ability to avoid future net costs to the Government will be determined by the market price of power and control of the costs Bonneville bears.

See comment 1.

See comment 11.

Financial and market analysis shows that the risk of loss from Bonneville's operations in a market-driven environment is a transitional one. Even under low energy price forecasts, eventually the price of energy is expected to rise above Bonneville's costs, at which point Bonneville should recoup the underrecoveries.[11] Furthermore, the Report could be read to imply that the amount at risk to Treasury is the whole of Bonneville's repayment obligation. This is not the case. Bonneville in any event would be able to exact market prices for its power on the West Cost market, which would enable Bonneville to meet a substantial portion of its repayment obligations in virtually all but the most dire scenarios of very low West Coast power prices and very high costs.[12]

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costs are allocated, could increase Bonneville's costs. Still other measures could be implemented, with associated capital and expense implications.

[11] By law, Bonneville is required to defer its payments to the Treasury in favor of meeting its nonTreasury payment obligations. *See* 16 U.S.C. 838k(b) and 838i(b). Any deferrals rollover and are repaid with then-current interest at Treasury rates. Department of Energy Order RA 6120.2. Thus, assuming that Bonneville's cost of power relative to market prices rebounds sufficiently, the Treasury would ultimately be made whole, on a present value basis, for any deferrals.

See comment 11.

Even now, there is evidence of underlying economic forces which indicates a move to a higher market clearing price than has recently been the case. Observers generally agree that these underlying conditions -- a strengthening West Coast economy (especially in California) and demand for electric power, new gas pipeline construction that will weaken regional price differentials now favoring West Coast natural gas consumers, and the expected retirement of older or marginally economic plants that contribute to the current West Coast energy surplus -- will continue. Moreover, as the Draft Report notes at Vol. VIII, page 5 a significant portion of Bonneville's costs consists of debt payments for three nuclear projects. Debt service for the projects falls substantially in 2011 as bonds for one of the projects are retired, thereby reducing Bonneville's overall cost of generating power. The effect becomes even more pronounced after 2018, when all of the nuclear project debt is retired. If other key components of Bonneville's cost profile, such as fish protection costs, can be held in check, Bonneville will have a significant cost advantage in the long-run.

Now in app. VIII, p. 110.

See comment 1.

On these bases, Bonneville believes that risk of loss to the Government is "reasonably possible" *only during a ten-year transition period after 2001.* After that period, Bonneville's costs and the price of its wholesale power should be well below market. Failing to underscore the transitional nature of the risks Bonneville faces draws an incomplete picture.

See comment 12.

A key factor in the Draft Report's conclusion on risk is that Bonneville has relatively few contractual commitments in place for the purchase of Federal power *at above current market rates/prices* for the period after 2001. At the request of the Department of Energy, in 1996 the four Pacific Northwest governors convened a "Comprehensive Review of the Northwest Energy System" (Comprehensive Review) to develop alternatives for energy future of the Pacific Northwest and Bonneville. The Comprehensive Review Final Report maps out a solution to Bonneville's cost recovery uncertainties. A central expectation underlying the Review is that the cost of Bonneville's power could be at or slightly below market for a short period after 2001 but in the longer term, the cost of Bonneville's electric power will be much below the market price. Playing on this expectation, the Comprehensive Review proposes a subscription process that seeks to induce historical customers to purchase power from Bonneville on a long-term, *cost of power* basis. Entities that do not so subscribe to pay cost-recovery rates would lose the ability later to purchase Bonneville at power at cost, thus foregoing the future benefit of purchasing low cost Federal power in a high priced market. Any FCRPS power not subscribed on a cost recovery basis would be marketed on the West Coast at market prices. Bonneville agrees that there is uncertainty whether the Comprehensive Review proposals will be implemented, primarily because of the reluctance of customers to bear the exposure to cost increases for fish protection, and because of questions about the acceptability to customers of a robust cost

[12] Congress recently granted Bonneville enhanced ability to market outside of the Pacific Northwest Federal power not sold to meet Pacific Northwest needs. Pub. L. 46-104. This helps assure that Bonneville can recoup West Coast, not merely Northwest, market prices for its excess power.

recovery mechanism to buttress the subscription process.[13] Nonetheless, Bonneville believes that the Comprehensive Review proposal has promise and the issues clouding a successful subscription process could be resolved to the Government's satisfaction.

4. Other Substantive Points With Which Bonneville Takes Issue

See comment 13.

(a) The Draft Report errs in claiming that the power marketing administrations (including Bonneville) are advantaged by the current practice of allowing them to repay the highest interest-bearing appropriated investments first. Unlike debt issuers in public markets, including Treasury, Bonneville has no debt instrument alternatives to minimize assigned interest expense on appropriated investments. In contrast, other debt issuers including private corporations, typically use a broad range of debt instrument alternatives, including notes, variable rate debt, and bonds with early redemption provisions, to minimize interest expense. Bonneville lacks this ability with respect to the appropriated investments. Moreover, if Bonneville has an appropriated investment that is assigned a relatively high interest rate, Bonneville lacks the ability to refinance that repayment obligation to take advantage of lower interest rate markets. The highest-interest-first method is a reasonable surrogate for the financing flexibility enjoyed by the Treasury and by Bonneville's competitors. In any event Congress only recently reviewed and confirmed in legislation the highest interest first practice. *See* 16 U.S.C. 838l.

See comment 1.

(b) The Draft Report errs in claiming that Treasury's borrowing practices are "inflexible in that it is generally unable to refinance or prepay outstanding debt in times of falling interest rates (Treasury borrowing practices)." While it is true that Treasury issues long-term debt without call provisions, Treasury has and uses substantial flexibility through other debt instruments, notes and bills, with shorter terms and lower interest rates to fund the Government's cash requirements and minimize interest expense. Again, it is the weighted average interest rate of the *portfolio* of Treasury debt, including bonds, notes, and bills, that reflects Treasury's cost of debt for purposes of comparison. Thus, to the extent one were to assert there is any lack of "flexibility" in Treasury's not issuing callable bonds, the associated costs should be attributed to Treasury, not Bonneville.

See comment 1.

(c) The Draft Report errs in suggesting that the power marketing administrations, including Bonneville, are advantaged by having "appropriated debt with maturities of up to 50 years which is beyond the maximum maturity of Treasury bonds." It is illogical to conclude that this results in a net cost to the Government. The interest rate environment at the time of the maturity of Treasury's bonds cannot be known when the appropriation repayment interest rates are assigned. Given this, there is substantial opportunity as well as risk to Treasury, particularly in view of the fact that Bonneville's outstanding appropriations were reset at prevailing market rates under the 1996 Appropriations Refinancing law discussed above.

[13] In testimony on June 15, 1997, before the Subcommittee on Energy and Water of the House Committee on Resources, Bonneville Administrator Randall W. Hardy described the need for "a contingent stranded cost recovery mechanism to help avoid burdening the United States taxpayer, who stands last in line of Bonneville's creditors . . . The Administration supports statutory charges which create a more robust contingent stranded cost recovery mechanism for Bonneville."

See comment 14.
Now on pp. 17, 18, 28, and 29.

(d) The Draft Report appears to compare Bonneville's wholesale power rates to retail power rates of investor-owned utilities. *See* Volume I, Pages 25-26, 48, "Average Revenue/kWh." If this is what is compared, the comparison is flawed. Retail rates include costs of distribution to end users, wholesale rates do not. Costs of distribution can be several mills per kilowatt hour.

We have previously forwarded to and discussed with your staff a number of technical and editorial comments to the Draft Report. Thank you for allowing us to comment on it.

Sincerely,

John S. Robertson
Deputy Administrator

Enclosure

The following are GAO's comments on the Bonneville Power Administration's letter dated June 27, 1997.

GAO Comments

1. Discussed in the "Agency Comments and Our Evaluation" section in the letter in volume 1.

2. The scope of this assignment did not include examining the public benefits that BPA and the other agencies that were the subject of our review provide to their respective regions. However, our report states that BPA has substantial financial responsibilities and costs with regard to fish and wildlife restoration, irrigation assistance, and the provision of power to residential and small farm consumers. We have also added a statement to the report's background section indicating that these responsibilities are the result of congressional mandates.

Additionally, the report describes in some detail fish costs, the related Memorandum of Agreement that is intended to help control those costs, and the annual magnitude of these costs. Specifically, the report describes the uncertainty with regard to whether the Memorandum of Agreement will be continued beyond 2001 as a factor increasing BPA's risk during the post-2001 period. The report also discloses that BPA paid $196 million in fiscal year 1996 to provide power to selected residential and small farm consumers and recognizes that BPA has an obligation totaling more than $800 million for irrigation debt.

3. Although we agree that BPA's fish costs constitute significant financial exposure, we do not concur with BPA's statement that they constitute the "greatest financial exposure apart from market prices." This statement ignores BPA's significant debt service obligations and the projected upward pressure on other operating costs. These costs, as the report discusses, significantly limit BPA's financial flexibility and its ability to meet competitive challenges.

4. Our report measures the net financing costs of debt outstanding at September 30, 1996. This debt was incurred by BPA from 1951 to 1996; therefore, using the interest rate for Treasury's overall bond portfolio, which includes bonds issued by Treasury over the last 30 years, is appropriate. We agree that this rate does not and should not reflect "current Treasury borrowing costs nor the rates at which Treasury lends to agencies."

5. We disagree. As a result of our analysis, we estimate that the fiscal year 1996 net financing cost to the federal government resulting from BPA's appropriated debt is $377 million. As discussed in the agency comments section of volume 1, the 9.0 percent interest rate on Treasury's outstanding portfolio of long-term bonds is the appropriate interest rate to use in estimating the federal government's net financing cost because it compares long-term debt to long-term debt. However, even if we had used the 6.7 percent interest rate proposed by BPA, the estimated fiscal year 1996 net financing cost to the federal government is $223 million, which represents a substantial cost to the federal government.

6. We believe that BPA's "high interest rate environments" assertion is negated by its ability to pay off high interest rate debt first. As a result, BPA's average interest rate on appropriated debt at September 30, 1996, was 3.5 percent. This low average interest rate results because very little appropriated debt incurred during "high interest rate environments" is currently outstanding. Over 81 percent of BPA's currently outstanding appropriated debt is at rates below 3.5 percent.

7. We discussed with cognizant Treasury officials BPA's assertion that the interest rates it paid on its Treasury bonds result in a markup of roughly 60 to 100 basis points over Treasury's borrowing costs. These officials disagreed with this assessment and noted that the difference between Treasury's borrowing costs and the rate BPA paid on its Treasury bonds is due primarily to the differences in the provisions of the borrowing terms under which each entity obtains funds. Many of BPA's Treasury bonds carry provisions which allow BPA to call the debt prior to its maturity, while the long-term bonds issued by Treasury generally carry no call provisions. As a result, Treasury bears additional interest rate risk as part of these transactions. According to Treasury officials, these provisions in BPA's Treasury bonds increase their value to BPA and require a higher interest rate to compensate Treasury for its increased risk. Thus, we continue to believe that the interest rate BPA paid on its Treasury bonds results in a reasonable approximation of the federal government's cost of providing the funds.

8. The characterization of BPA's appropriated debt as of the end of fiscal year 1996 and the weighted-average interest rate associated with this appropriated debt were taken directly from the audited financial statements included in BPA's 1996 annual report. The difference between BPA's appropriated debt after its restructuring as shown in our draft report and the figure reported by BPA here relates to the treatment of

construction work in progress. Further discussion with BPA staff indicates that the correct appropriated debt balance is $4.29 billion. We have changed our report to reflect this amount.

9. Our review of TVA and BPA appropriated debt entailed an examination of whether or not the Treasury was receiving a return sufficient to cover its borrowing costs. Unlike BPA, the terms of TVA's appropriated debt require payment of market interest rates on all of its appropriations, whether or not they are to be repaid to the Treasury. These rates are reset on an annual basis. For example, in 1982, because of high inflation and resultant high interest rates, TVA's weighted-average interest rate on its appropriated debt was over 12 percent, while BPA's was approximately 3.3 percent. In 1996, TVA paid an interest rate of approximately 6.87 percent, while BPA's weighted-average interest rate was about 3.5 percent. Because TVA is required to pay these market rates of interest, which are re-set to Treasury rates every year, the Treasury is receiving a return sufficient to cover its borrowing cost.

10. We agree that the marketplace is likely to become increasingly competitive and that BPA will be subject to considerable market risk in the future. This risk was discussed extensively in our report, and was a primary factor in the report's risk analysis. We agree that the prices BPA will be able to charge in the future will be driven by market prices; the question is whether the revenues received will be adequate to recover all of BPA's costs. After 2001, considerable uncertainty exists with regard to market prices, customer contract extensions, and the level of BPA's costs—giving rise to our report's conclusion that the risk of loss to the federal government after 2001 is "reasonably possible."

11. Our draft report stated that the federal government would have financial losses if BPA (or the other entities reviewed) was unable to repay debt owed to the federal government. We do not state that the entire federal government's financial involvement is likely to be lost. In addition, we added a comment to volume 1 of the final report indicating that the power-related assets of BPA or the other entities would be available to the federal government to sell to offset some portion of any actual losses the federal government incurred as a result of its financial involvement with these entities.

12. We agree that there is uncertainty with regard to implementation of the Comprehensive Review's recommendations. Since these recommendations

have not been implemented, we did not assess the possible effect that they would have on the federal government's financial risk.

13. We continue to believe that BPA's (and the other PMAS') ability to repay the highest interest bearing debt first constitutes a major advantage. This practice has allowed the PMAs (including BPA) to keep the weighted-average interest rate on appropriated debt at levels that are substantially below any Treasury market interest rates that have been in effect for decades. BPA's fiscal year 1996 average interest rate on appropriated debt of 3.5 percent is evidence of the benefit of the repayment provisions.

14. As stated in our report, we compared wholesale average revenue per kWh for all entities.

Comments From the Tennessee Valley Authority

Note: GAO comments supplementing those in the report text appear at the end of this appendix.

Tennessee Valley Authority, 400 West Summit Hill Drive, Knoxville, Tennessee 37902-1499

David N. Smith
Chief Financial Officer and Executive Vice President
Financial Services

July 10, 1997

Ms. Linda Calbom
Director, Civil Audits
Resources, Community, and Economic Development Issues
U.S. General Accounting Office
441 G Street, N.W.
Washington, DC 20548

Dear Ms. Calbom:

Thank you for coming to Knoxville to discuss the GAO's draft report titled Federal Electricity Finances. We appreciate the opportunity to provide a response to those issues that are important to TVA.

Part I: Current, Recurring Costs to the U.S. Government

See comment 1.

We were pleased to see that one of the principle conclusions of the report is that TVA's power program is not currently costing the federal taxpayer anything, except the $700,000 per year for a portion of the pension cost for some 160 TVA employees covered by the Civil Service Retirement System.

See comment 2.

TVA is, in fact, providing a return to the U.S. government as TVA's owner which considerably exceeds the cost of the government's capital invested in TVA prior to 1959. The items below highlight the financial benefits that the government receives from the TVA relationship.

Appropriation Investment

As the report indicates, TVA has not received any appropriated funds for its power program since it became self-financing in 1959 with the amendment to the TVA Act that restructured its power program.

Prior to 1959, the U.S. taxpayers had invested nearly $1.4 billion in the TVA power program, and TVA had repaid almost $200 million of that amount. Under the 1959 self-financing amendment, TVA is obligated to repay $1 billion of the remaining $1.2 billion of appropriation investment. The current balance of the appropriation investment is about $600 million which, together with about $3.4 billion in earnings that have been reinvested in the power program, represent the Government's equity in TVA.

Ms. Linda Calbom
July 10, 1997
Page 2

In addition, each year TVA pays to the Treasury a return, or dividend, on that investment. Because the rate at which the annual return payment is calculated equals the Treasury's current average cost of money, maintaining the Government's investment in TVA costs the taxpayers nothing. Under the 1959 law, TVA has actually paid the Government a total of about $3 billion—$2.3 billion in the form of annual returns (or dividends) on the taxpayer investment and $0.7 billion as a repayment of that investment.

Federal Financing Bank Debt

See comment 3.

The GAO report should include in its presentation of "annual cost to the government" an *income* item for the approximately $100 million that TVA pays the Treasury each year in excess of the government's current cost of financing these loans. The $3.2 billion which the Federal Financing Bank (FFB) loaned to TVA at an average interest rate of 9.7 percent is being financed today by the Treasury at a rate less than 7 percent. The difference results in about $100 million per year income to the Treasury. Recent Treasury actions demonstrate the financial value of these FFB loans to TVA. The U.S. Treasury used TVA's $3.2 billion FFB debt to collateralize about $4.0 billion of U.S. Treasury securities, thereby realizing a gain of some $800 million.

Further, under the terms of the FFB loans, TVA paid a fee ranging from 1/8 to 3/8 percent above the government's cost of money for similar maturities. The cumulative amount of fees paid by TVA to FFB for borrowings since 1974 total $264 million.

Civil Service Retirement System

See comment 4.

GAO includes in its report an estimated $700,000 annual "cost to the government" item for some 160 TVA employees who are covered under one of the civil service pension plans. This relates to the "unfunded" portion of the federal pension plan. TVA, of course, follows the federal regulations which govern the employer/employee contributions for the federal plan.

Under federal law, employees who transfer from another federal agency to TVA are allowed to continue to be covered under the Civil Service Retirement System. TVA has no control over the pension contribution rules for its employees covered by the Civil Service Retirement System.

We would note that the Budget Reconciliation bills presently being considered by Congress will establish higher contribution levels for all Federal agency employers and should eliminate this annual cost item.

Most of TVA's 15,000 employees as well as some 20,000 TVA retirees are covered by the TVA Retirement System and that cost is fully covered by TVA.

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Part II: Risk Exposure to the U.S. Government

We would also like to offer our comments related to the second objective of the study, which was to examine both the current and future "risk of loss" to the government from its involvement with electricity-related programs.

Current Risk

We agree with GAO's assessment that the current risk of loss to the government from obligations related to TVA is *remote*, given the various statutory and contractual constraints that define TVA's current environment.

See comment 5.

GAO quantifies the government's total direct and indirect financial involvement with TVA's power program at about $28 billion—the sum total of TVA's outstanding debt plus the government's equity investment. We emphasize that *this does not mean the government is at risk of losing $28 billion*, as the value of TVA's future earning power and its assets offset TVA's liabilities.

Future Risk

See comment 3.

We also concur that there are a host of uncertainties about the future of the utility industry and possible changes in the regulation of both investor-owned and public utilities. Nonetheless, we believe the GAO's assessment of the government's long-term risk of loss as *reasonably possible* is more negative than is warranted.

The following comments indicate that TVA is prepared to compete in any plausible future scenarios that may occur within a restructured electric utility marketplace.

TVA's Competitive Position

As you pointed out, TVA has taken several steps over the past 10 years to improve its competitiveness. Actions taken by TVA management include holding rates steady for 10 years, reducing expenses by nearly $800 million, capping the debt below the Congressionally mandated ceiling, and reducing the workforce from 34,000 to 15,000. And TVA's generating plants and transmission system are operating more efficiently now than they have in decades. With the successful return of Browns Ferry unit 3 and the completion of Watts Bar unit 1, both during fiscal year 1996, the TVA generating system now includes 5 operating nuclear units—none of which are on the NRC "watch list."

All of these actions have resulted in a total TVA production cost of 3.6 cents per kilowatt hour, compared to a national industry average of 5.5 cents per kilowatt hour, making TVA the second lowest-cost power producer among the nation's top 50 utilities. TVA and its distributors offer electricity to residential customers at the average price of 5.9 cents per kilowatt hour, compared to a national industry average of 8.3 cents.

TVA is continuing to work hard to improve efficiencies and lower costs throughout the corporation as we prepare for a restructured electric utility industry.

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TVA's current market is comprised of 160 distributors and 67 directly-served customers served through its 17,000 miles of centrally-located transmission lines. TVA has rolling 10-year contracts with 159 of its 160 distributors. In addition to the 10-year rolling contracts, several distributors, including those in Mississippi and Fort Payne, Alabama, signed an agreement this year to purchase electricity from TVA for a minimum of 5 years before they could issue notice on their 10-year contract, making their contracts, in essence, 15-year contracts. TVA recently created a new Customer Service and Marketing Group to expand relationships with existing customers and to seek new business opportunities.

We are preparing a long-range financial plan to increase TVA's financial flexibility. The plan will allow us to pay down debt and convert more of our fixed costs to variable costs. This will enable TVA to respond quickly to the volatility in both price and volume that will occur in a restructured electric utility industry. TVA's projected future cost of power will continue to be competitive, even under a range of plausible future market clearing prices.

We are confident that we can continue to successfully compete in a restructured electric utility industry.

Treatment of TVA's Deferred Nuclear Units

See comment 6.

In its report, GAO takes exception to TVA's accounting treatment of its 3 deferred nuclear generating units—Bellefonte units 1 and 2 and Watts Bar unit 2. GAO concludes that these units will never be finished and accordingly TVA should begin amortizing, or writing off, this cost of approximately $6.3 billion.

The TVA Board, which acts as the regulator of TVA's electric rates, has determined—based on analyses by nuclear experts from both inside and outside TVA—that the passage of time has not prohibited the completion of the deferred units, and completion of these units can still be achieved in an economically feasible manner. Further, the current TVA Board has taken actions to systematically assess and complete unfinished units. This strategy has proven to be successful as evidenced by the May 1996 completion and superior operating performance to-date of Watts Bar unit 1—a unit that was under construction for 20 years. The TVA Board is applying the same evaluation process to the currently deferred units and, as regulator, has determined that it is not prudent to begin recovering the cost of these units (except for interest cost) until such time as these units begin operating.

The TVA Board has determined that it is *not* probable at this time that these assets will be abandoned. Accordingly, the application of Statement of Financial Accounting Standards No.90, "Regulated Enterprises - Accounting for Abandonments and Disallowances of Plant Costs" is not appropriate.

TVA's Exposure to Higher Interest Rates

See comment 7.

GAO's report makes the point that TVA's annual interest expense, which equals about one third of TVA's annual revenue, is vulnerable to increases in interest rates.

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The average maturity of TVA's debt portfolio is about 19 years. Therefore, the only long-term debt affected by a significant increase in interest rates would be any issues that were maturing and required refinancing. Typically, this is between $1 billion and $2 billion a year. If interest rates were 1 percent higher than the existing rates on these maturing issues, for example, TVA's interest expense would increase by $10-20 million per year. Of course, *decreases* in interest rates would have the opposite effect. TVA also maintains about $2 billion of short-term debt which would also be impacted by interest rate changes.

See comment 3.

As discussed above, TVA also has $3.2 billion in debt owed to the Federal Financing Bank with an average interest rate of nearly 10 percent—about 3 percent higher than current market levels. If TVA were allowed to refinance the FFB debt at current market levels, the savings to TVA would be in the range of $100 million per year and would significantly offset any increase in interest expense as a result of higher interest rates in the future.

Characterization of TVA's Tax Advantage

See comment 8.

The GAO report compared a composite tax rate for private power companies of 14 percent of revenue with a rate for TVA of about 5 percent of revenue. This comparison is misleading because it does not distinguish between two fundamentally different kinds of taxes. Some taxes are based on certain *gross* levels of activity (e.g. gross receipts, gross property values). Such taxes are fundamentally different from income taxes which are based on *net* profit. Since public power entities, including TVA, are basically non-profit operations, they would pay little or no income tax even if they were not exempt from income tax laws. As such, GAO should show separate comparisons for income taxes and non-income taxes.

TVA does pay most Federal excise taxes and it pays 5 percent of its nonfederal energy sales revenue to State and local governments in lieu of the gross receipts and property taxes that would be applicable if it were a private corporation. In addition, the municipal and cooperative distributors of TVA power—which should be combined with TVA for purposes of comparing the total TVA utility system with investor-owned utilities—pay State taxes or equivalents. For fiscal year 1995, TVA and its distributors actually paid more (as a percent of revenue) in taxes *other than income* than did neighboring large investor-owned utilities in the southeastern region of the U.S.

Liabilities that Have Already Been Satisfied by TVA

See comment 9.

One issue *not* discussed in the GAO report that TVA believes deserves mentioning is the fact that TVA has already provided funding that is adequate to satisfy two significant long-term liabilities—nuclear unit decommissioning costs and employee pension costs.

In the past year, the TVA Board took action to set aside in trusts enough funds to completely cover the estimated present value of the cost of decommissioning TVA's nuclear units at their license expiration dates. TVA is a step ahead of many nuclear utilities in this area even though it is not required, as an entity of the federal government, to establish a decommissioning fund.

Secondly, unlike the federal civil service pension system, the TVA Retirement System is soundly funded. The value of the system's assets are about 150 percent of the value of its liabilities.

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Both items represent significant liabilities that neither TVA nor the federal government need be concerned about in the future.

Thank you for the opportunity to provide our comments on the draft report. Please contact us if you have questions or would like to discuss any of our comments.

David N. Smith
Executive Vice President and
Chief Financial Officer

The following are GAO comments on TVA's letter dated July 10, 1997.

GAO Comments

1. We agree that TVA's power program is costing the federal government about $0.7 million per year for a portion of the pension cost for the TVA employees covered by the federal Civil Service Retirement System (CSRS). However, we did not analyze every aspect of TVA's program to determine the total cost of TVA to the federal or state governments. As agreed with the requesters and as pointed out in both volume 1 and appendix II of volume 2 of our report, our review did not (1) estimate the foregone revenue for federal, state, or local governments resulting from the tax-exempt status of TVA, (2) estimate the foregone revenue for federal and state governments resulting from tax-exempt debt instruments issued by TVA, or (3) quantify the amount of potential future losses to the federal government. Therefore, we are able to state only that for those costs we analyzed, TVA's power program does not result in costs to the federal government, except for a small portion of the pension costs of TVA employees covered by the CSRS.

2. We disagree. As noted in TVA's comments, as of September 30, 1996, TVA considered the government's equity in TVA to be approximately $4 billion. This amount consisted of about $608 million in appropriation investment[1] (referred to as appropriated debt in our report) and about $3.4 billion in retained earnings.[2] Using this definition of the federal government's equity, the federal government's "capital invested in TVA prior to 1959" would have been limited to the appropriation investment and retained earnings. TVA does not pay the federal government an annual return (interest income) on its retained earnings. It pays an annual return on the government's appropriation investment only. The method for calculating this return ensures that the annual payments made by TVA result in a return to the federal government that covers its borrowing costs. TVA's comments tend to support our position. TVA stated, "Because the rate at which the annual return payment is calculated equals the Treasury's current average cost of money, TVA costs the taxpayers nothing."

3. Discussed in the "Agency Comments and Our Evaluation" section of the letter in volume 1.

[1]TVA's appropriation investment primarily represents appropriations received from the federal government prior to 1959 to build capital projects. The 1959 amendments to the TVA Act required TVA to begin (1) repaying about $1 billion of the balance of this account and (2) paying the federal government an annual market rate of return on the unpaid portion of the balance.

[2]Retained earnings represent the cumulative revenue in excess of accrued expenses. These earnings have been used by TVA primarily to finance capital assets.

4. We concur that TVA is required to follow the federal regulations that govern the employer and employee contributions for the CSRS and therefore, has no control over the pension contribution rules for its employees that are covered by this pension plan. As noted in appendix II, in fiscal year 1996, OPM reported that the full (normal) cost to the federal government of the pension benefits earned by CSRS employees was 25.14 percent of gross salaries. However, since TVA is required to contribute 7 percent and TVA's employees are required to contribute another 7 percent, a funding deficiency of 11.14 percent (25.14 less 14 percent) of annual salaries existed for each CSRS employee. Since all new federal employees are covered by the FERS pension plan, which is fully funded, the future cost to the federal government of TVA's CSRS employees should continue to decline. We also concur that the passage of any legislation to increase the contributions of the employees and/or employers would decrease the cost to the federal government of TVA's CSRS employees. However, because of the present funding shortfall for the CSRS pension plan, TVA, like most other government agencies, is not recovering the full pension cost for the TVA employees covered by CSRS.

5. We agree with TVA that our assessment of the likelihood of loss did not consider proceeds that the federal government might receive from the sale of TVA's assets. We discuss this limitation in the scope of our review in appendix II of volume 2 of our report. We have added a note to table 3 in volume 1 of our report stating that the federal government could sell the power-related assets of RUS borrowers, the PMAs, and TVA to offset some portion of any actual losses the federal government might incur as a result of its financial involvement with these entities.

6. We believe the prospects for TVA completing the deferred units as nuclear facilities is unlikely, especially given TVA's recently issued 10-year business plan that provides no funding for completion of these plants. Even if these units are converted to an alternative fuel source, the potential savings over the construction of a new plant are very small. Thus, most of the costs from the deferred units are sunk and will not be utilized as nuclear plants or converted power plants. It is unlikely that most, if any, of the costs incurred on the deferred units to date will be used directly to generate electricity. Therefore, we continue to believe that TVA should apply SFAS No. 90 to the deferred nuclear assets and begin to recover these costs immediately.

If TVA delays recovering the $6.3 billion, while it retains the monopoly-like protections described in this report, it could end up having to recover these costs from ratepayers when it is facing a competitive environment and may not have the ability to set rates at a level sufficient to recover all of these costs. Therefore, TVA's continued exclusion of these costs from charges to ratepayers reduces the likelihood of recovery from ratepayers and puts the federal government at increased risk of absorbing these costs in the future.

7. We agree with the facts as stated by TVA, and we believe this information supports our point that TVA is subject to interest rate risk. Our report points out that as TVA's approximately $28 billion in debt matures, the portion that is not repaid will likely need to be refinanced, thus exposing TVA to the risk of rising interest rates and even higher financing costs. As of September 30, 1996, TVA had approximately $8 billion in long-term debt that will mature and need to be refinanced over the next 5 years. By the end of this 5-year period, for every 1 percentage point change in TVA's borrowing costs for that $8 billion, its annual interest expense will increase or decrease by $80 million per year. We also agree with TVA that its approximately $2 billion in short-term debt represents additional interest rate risk. We have revised our report to reflect this fact.

8. Our report points out that TVA has an inherent cost advantage because it operates as a nonprofit and pays substantially less taxes than its likely competitors—IOUs. We agree that as a nonprofit operation, TVA would pay little or no income taxes because it has minimal net income. However, the real underlying advantage TVA has over IOUs is that it does not have to include a rate of return, which results in taxable income, in its electricity rates. This allows TVA to keep its rates proportionately lower than if a rate of return had to be generated through revenues.

TVA also mentioned that to fairly compare the taxes paid by TVA to IOUs we should include the taxes paid by TVA's distributors. We agree and have revised our report to reflect this information. By including the taxes paid by TVA's distributors, the percent of taxes paid by TVA and its distributors in fiscal year 1995 was about 6 percent of gross power revenue, which is still substantially less than the average annual taxes paid by IOUs.

9. The primary objectives of our report were to (1) identify the net recurring cost to the federal government from its electricity-related activities and (2) assess the risk of future loss to the federal government from its indirect and direct involvement in RUS, the PMAs, and TVA. We agree with TVA that as of September 30, 1996, it had taken steps to provide adequate funding for two of its significant long-term

liabilities—decommissioning costs and pensions. Therefore, there was no need to include these liabilities in our discussion of the net cost to the federal government or risk of future losses due to the federal government's involvement in TVA. However, TVA's funding for the actual liabilities of these programs is contingent upon the accuracy of their assumptions and the extent to which future events conform to the schedule used in the assumptions.

Major Contributors to This Report

Accounting and Information Management Division, Washington, D.C.

Gregory D. Kutz, Associate Director
McCoy Williams, Assistant Director
Robert E. Martin, Senior Audit Manager
Donald R. Neff, Senior Audit Manager
Dianne Langston, Audit Manager
Patricia B. Petersen, Auditor
Meg Mills, Communications Analyst

Office of the General Counsel, Washington, D.C.

Thomas H. Armstrong, Assistant General Counsel
Amy M. Shimamura, Senior Attorney

Atlanta Field Office

William J. Cordrey, Senior Auditor
Johnny W. Clark, Auditor
Marshall L. Hamlett, Auditor

Kansas City Field Office

Arthur W. Brouck, Senior Auditor
Christie M. Arends, Auditor
Gary T. Brown, Auditor
Karen A. Rieger, Auditor

Seattle Field Office

David W. Bogdon, Senior Evaluator
Laurence L. Feltz, Senior Evaluator

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