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Report to Congressional Requesters

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POWER MARKETING ADMINISTRATIONS

Cost Recovery, Financing, and Comparison to Nonfederal Utilities

GAO

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The Honorable John T. Doolittle
Chairman, Subcommittee on Water
and Power Resources
Committee on Resources
House of Representatives

The Honorable George Miller
Ranking Minority Member
Committee on Resources
House of Representatives

As requested, this report presents the results of our review of three power marketing administrations' (PMAS) cost recovery practices, financing, and comparison to nonfederal utilities.

We are sending copies of the report to appropriate House and Senate committees, interested Members of the Congress, the PMAS, the Secretary of Energy, the Secretary of the Interior, the Secretary of Defense, the Office of Management and Budget, and other interested parties. Copies will also be made available to others upon request.

I may be reached at (202) 512-8341 if you have any questions about this report. Major contributors to this report are listed in appendix VII.

Linda M. Calbom
Director, Civil Audits

Executive Summary

Purpose

In recent years, the Congress has focused increasing attention on the pros and cons of privatizing the federal power marketing administrations (PMAS), which transmit and sell electric power generated mainly at federal hydropower facilities. Most of these facilities were originally designed for other purposes in addition to producing electricity. The Chairman, Subcommittee on Water and Power Resources, House Committee on Resources, and the Committee's Ranking Minority Member asked GAO to provide information about three of these PMAS—the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration. As requested, GAO's review addressed three main questions:

- Have all power-related costs incurred through September 30, 1995, been recovered through the PMAS' electricity rates?
- Is the financing for power-related capital projects subsidized by the federal government and, if so, to what extent?
- How do PMAS differ from nonfederal utilities and what is the impact of these differences on power production costs?

We were not asked to and did not address whether any changes in PMA cost recovery practices or financing should be made.

Background

The three PMAS, part of the Department of Energy (DOE), market primarily wholesale power in 30 states produced at large, multiple-purpose water projects. Collectively, in fiscal year 1995, they had revenues of almost $1 billion. Most of the power they sell is produced at 102 hydroelectric dams built and run primarily by the U.S. Army Corps of Engineers and the Department of the Interior's Bureau of Reclamation (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. To transmit this power, Southwestern and Western have their own transmission facilities, while Southeastern relies on the transmission services of other utilities.

The three PMAS receive annual appropriations to cover operating and maintenance (O&M) expenses and, if applicable, the capital investment in transmission assets. Federal law calls for PMAS to set power rates at levels that will repay these appropriations as well as the power-related O&M and capital appropriations expended by the operating agencies generating the power. DOE's implementing order specifies that unless otherwise prescribed by law, appropriations used for O&M expenses be recovered in the same year the expenses are incurred, but that appropriations used for capital investments (which we refer to as appropriated debt[1]) be recovered, with interest, over periods of up to 50 years. At the end of fiscal year 1995, the three PMAS had about $5.4 billion of appropriated debt outstanding. In addition, Western is required to recover about $1.5 billion of capital costs related to assistance on completed irrigation facilities (which we refer to as irrigation debt), without interest, with repayment periods of up to 60 years.

Results in Brief

GAO identified five main power-related costs that have not been fully recovered by one or more of the PMAS through rates: (1) pensions and postretirement health benefits for current employees, (2) construction costs for some power-generating and transmission projects, (3) construction and O&M costs that have been allocated to irrigation facilities at the Pick-Sloan Program that are incomplete and infeasible, (4) costs of mitigating the environmental impact of certain water projects, and (5) certain O&M and interest expense payments due from Western. In some cases, PMAS are not required to recover these costs because of specific legal provisions, while in others, the DOE implementing order either excludes the costs or is not specific and has been interpreted by the PMAS to exclude the costs. GAO estimated that these unrecovered costs amounted to approximately $83 million for fiscal year 1995 and cumulatively could be as much as $1.8 billion as of September 30, 1995.

GAO also determined that financing of power-related capital projects is subsidized by the federal government and estimates that the financing subsidies were about $200 million in fiscal year 1995. GAO estimates that the cumulative financing subsidy over the last 30 years has been several billion dollars. Financing subsidies result from DOE policies that require PMAS to pay off high interest appropriated debt first while retaining low-interest debt. Also, prior to 1983, the interest rates imposed at the time the funds for capital projects were appropriated were generally below U.S. Department of Treasury rates. Financing subsidies exist because Treasury's cost of funds is greater than the interest rates on PMA appropriated debt. For example, the fiscal year 1995 weighted average interest rate for the Southwestern Power Administration's $686 million of outstanding appropriated debt was 2.9 percent compared to Treasury's September 30, 1995, weighted average interest rate on its bond portfolio of

[1]GAO calls 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 the Treasury.

9.1 percent. Treasury's cost of funds is relatively high because of its inability to refinance or prepay its debt.

The types of unrecovered costs described above are typically included in power production costs and electricity rates established by nonfederal utilities. In addition, nonfederal utilities, on average, generally pay higher interest rates on debt than do PMAS. PMAS have other inherent advantages over nonfederal utilities. One such advantage is that nearly all of the power marketed by these three PMAS is hydropower primarily generated from projects built 30 to 60 years ago. This hydropower is a low cost energy source compared to coal and nuclear fuels, which are the primary energy sources used by other utilities. Another advantage is that PMAS, as federal agencies, do not, for the most part, pay taxes. The unrecovered costs, financing subsidies, and inherent cost advantages have resulted in the PMAS' being a low cost marketer of wholesale electric power. In 1994, the PMAS average revenue per kilowatthour (kWh) for wholesale sales was approximately 40 percent less than the average for nonfederal utilities.

PMAS also have disadvantages compared to nonfederal utilities. For example, Western is required to recover certain nonpower costs through rates, such as the Hoover Dam Visitor Center and irrigation assistance totaling $1.5 billion. Increased competition in wholesale electricity markets is projected to lower rates, which will magnify the importance of the PMAS' marketing low cost power because customers are able to buy electricity from suppliers that have the most advantageous rates.

In aggregate, we estimate that the unrecovered power-related costs and financing subsidy total about $300 million for fiscal year 1995 and billions of dollars over the last 30 years. It is important to note that the PMAS are generally following applicable laws and regulations regarding recovery of power-related costs discussed in this report and financing of capital projects.

GAO's Analysis

Rates Do Not Recover All Power-Related Costs

The Reclamation Project Act of 1939 and the Flood Control Act of 1944 generally require that the PMAS recover through power rates the costs of producing and marketing federal hydropower. However, these acts do not define which costs are required to be recovered. In addition, DOE's implementing Order RA 6120.2, which was issued in 1979 and last revised in 1983, excludes certain costs associated with nonoperational facilities and is not specific about recovery of others. Where the order is not specific, PMAs have interpreted it to exclude certain costs from rates. To define the full cost of power production and marketing, GAO referred to Office of Management and Budget (OMB) Circular A-25, "User Charges," industry practice, and federal accounting standards. These criteria indicate that the full cost of producing and marketing federal hydropower would include all direct and indirect costs incurred by the PMAs, operating agencies, and other agencies involved in power-related activities. GAO identified five main power-related costs that meet these criteria that have not yet been fully recovered through electricity rates.[2]

First, the three PMAs do not recover the full cost of power-related postretirement health benefits and Civil Service Retirement System (CSRS) pension benefits for current PMA and operating agency employees. For fiscal year 1995, GAO estimates that these unrecovered costs were about $16 million. The annual funding shortfall associated with CSRS pension benefits will be eliminated over time as CSRS employees leave the government and are replaced by employees covered by the Federal Employees Retirement System (FERS), for which pension benefits are fully funded. The annual funding shortfall associated with postretirement health benefits, however, will not be eliminated as a result of this transition, since it is an entirely separate benefit program. As of September 30, 1995, GAO estimates that the cumulative unrecovered costs associated with postretirement health benefits and CSRS pension benefits were about $436 million.

Second, all three PMAs had incurred costs and/or had costs allocated to them for projects that were completed or under construction for which full costs were not being recovered. In some cases, this was because the power-generating projects had never operated as designed. In accordance with DOE guidance, PMAs set rates that exclude the costs of non-operational parts of power projects, including capitalized interest. For example, at the Russell Project, partially on line since 1985, litigation over excessive fish kills has kept four of the eight turbines from becoming operational. As a result, about one-half of the project's construction costs have been excluded from Southeastern's rates. It is unclear whether these costs, totalling $488 million as of September 30, 1995, will be recovered if the project never operates to the capacity designed. In other cases, the

[2]GAO did not assess the reasonableness of the methodologies used by the operating agencies to allocate costs to power users and therefore could not determine whether these allocations result in recovery of all applicable operating agency power costs.

tenuous financial condition of completed projects also raises questions about whether related power costs will be recovered. For example, Western is currently selling electricity from the Washoe Project for less than 20 percent of what it costs to produce. According to Western, this situation is the result of relatively high construction costs and drought conditions. According to Western's 1995 annual report: "Based on current conditions, it is unlikely the project will be able to generate sufficient revenues to repay the Federal investment." For the same reasons, GAO believes that the Washoe Project is unlikely to generate sufficient revenue to repay all O&M and interest expenses.

Third, as GAO reported in May 1996,[3] at the Pick-Sloan Missouri Basin Program (Pick-Sloan), about $454 million of capital costs for hydropower facilities and water storage reservoirs have been allocated to authorized irrigation facilities that are infeasible and therefore not expected to be completed. Western is currently selling electricity to its power customers that would have been used by the irrigators had the irrigation facilities been completed. As long as the $454 million is allocated to incomplete irrigation facilities, recovery by Western will not be required. If the facilities were completed and the capital costs were determined to be beyond the irrigators' ability to repay, then Western would be required to recover most of these irrigation costs without interest. If these costs had been allocated based on the actual use of the hydropower facilities and water storage reservoirs, they would have been allocated primarily to power production and recovered, with interest, through electricity rate charges within 50 years of completion. Under the current repayment criteria, it is unlikely that Western will be required to recover the principal or any interest on these capital costs. In addition, since 1987, $13.7 million ($15.3 million in constant 1995 dollars) of power-related O&M expenses incurred by the Army Corps of Engineers at Pick-Sloan have been allocated to incomplete irrigation facilities and thus are not being recovered through power rates.

The methodology that resulted in allocating power-related capital and O&M costs to the incomplete irrigation facilities was developed decades ago in anticipation of the completion of all planned irrigation facilities. This methodology is still being used and will continue to increase these unrecovered power costs. However, as GAO also reported in May 1996, changing the terms of repayment to recover any of the $454 million investment would require congressional action. Additionally, any changes

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

between the program's power and irrigation purposes may also 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 facilities that are now not likely to be constructed.

Fourth, 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 are legislatively excluded from Western's rates. For the Shasta Dam, these costs totaled $9.7 million in 1995 and $5.4 million in 1994. For the Glen Canyon Dam, they totaled $13.9 million and $12.5 million for the same 2 years. The total cumulative legislatively excluded environmental costs for the two projects were $134.3 million ($152.5 million in constant 1995 dollars) as of September 30, 1995.

Fifth, as of September 30, 1995, Western had unrecovered O&M and interest expense payments relating to nine of its 15 projects. These "deferred payments" are to be repaid to Treasury, with interest. According to Western, these deferred payments are primarily due to drought conditions which reduced streamflow and hence the ability to generate electricity in the late 1980s and early 1990s. The balance of Western's deferred payments decreased from about $250 million as of September 30, 1994, to about $196 million as of September 30, 1995. Western officials have told us they expect to recover the majority of these costs over time.

Favorable Terms Result in Subsidized Financing

Power-related capital projects are financed, primarily, with appropriated funds. Federal legislation and DOE policy enable PMAs to implement flexible financing terms that allow the accumulation of large amounts of appropriated debt at low interest rates. PMAs have low interest rates on appropriated debt for two primary reasons. First, DOE's policy generally requires PMAs to pay off outstanding debt with the highest interest rate first, regardless of maturity dates. (This does not apply to any debt due in a given fiscal year. Such debt must be paid first, regardless of interest rate.) Second, prior to 1983, capital projects were generally financed at interest rates lower than the then prevailing comparable Treasury interest rates. Because repayment terms on below market interest rate appropriated debt are up to 50 years, some of this debt could remain outstanding for several more decades.

A financing subsidy exists because the interest expense incurred by Treasury on its debt is higher than the interest income Treasury receives from the PMAs for their appropriated debt. This financing subsidy is a result of the flexible repayment terms allowed the PMAs by federal law and DOE regulations and the below market interest rates incurred on appropriated debt prior to 1983. For fiscal year 1995, the average interest rates on appropriated debt were 2.9 percent for Southwestern, 4.4 percent for Southeastern, and 5.5 percent for Western. The average interest rate on Treasury's outstanding bond portfolio as of September 30, 1995, was 9.1 percent. GAO estimates that the financing subsidy for the three PMAs was about $200 million in fiscal year 1995. Over the next several decades, as the pre-1983 appropriated debt is paid off, the PMAs' financing subsidy should decrease. However, the PMAs' ability to repay high interest debt first has been a factor and likely will continue to contribute to PMA average interest rates being below the effective Treasury average interest rate. In addition, Treasury's borrowing practices contribute to the magnitude of the financing subsidy. Treasury's inability to refinance or prepay outstanding debt in times of falling or low interest rates is part of the reason for its relatively high 9.1 percent average cost of funds in fiscal year 1995.

Federal Subsidies and Inherent Advantages of PMAs Result in Low Cost Power

PMAs market low cost wholesale electricity. The PMAs' average revenue per kWh for wholesale sales was substantially lower in 1994 than averages for other utilities. In 1994, the national wholesale average revenue per kWh was 3.5 cents for investor-owned utilities (IOUs) and 3.9 cents for publicly owned generating utilities (POGs). This compares to 1.49 cents for Southwestern; 1.82 cents for Western; and 1.98 cents for Southeastern. GAO believes that average revenue per kWh is a strong indicator of the relative power production costs and overall competitive position of the PMAs compared to other utilities. Except for several rate-setting systems at Western, and one at Southeastern, the PMAs' power production costs appear to be stable and well below the costs for nonfederal utilities in their respective areas of the country.

In addition to unrecovered costs and subsidized financing, other inherent advantages contribute to the PMAs marketing low cost power. One key advantage is PMA access to and almost exclusive reliance on hydropower primarily produced by projects built 30 to 60 years ago, a low cost means of generating electricity. Unlike the PMAs and operating agencies, IOUs build new capacity to meet future customer needs and must rely on more expensive sources of electricity, such as coal and nuclear energy. In 1995, about 55 percent of the electricity generated in the United States by IOUs and POGs was fueled by coal, and another 25 percent by nuclear energy. PMAs, as federal agencies, generally do not pay taxes, whereas other utilities pay federal and state income taxes, property taxes, and other taxes, or payments in lieu of taxes. In 1994, IOUs paid an average of about 14 percent of revenues for taxes, and POGs paid an average of 5.8 percent of revenues to state and local governments in lieu of taxes.

PMAs also have certain disadvantages compared to nonfederal utilities. For example, Western is required to recover through rates the cost of the Hoover Dam Visitor Center totaling an estimated $124 million. Additionally, Western is required to recover approximately $1.5 billion related to construction costs on completed irrigation facilities. 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. Recent developments are projected to decrease average wholesale electricity rates, which could impact the competitiveness of certain of the PMAs' higher cost rate-setting systems. Competition in the wholesale electricity market is increasing due to legislation such as the Energy Policy Act of 1992, which encouraged additional wholesale suppliers to enter the market and provided greater access to other utilities' transmission lines. Another factor that could impact the PMAs is the increasing influence of low cost independent (nonutility) power producers (IPPs). Construction of increasingly efficient natural gas-fired combustion turbines by IPPs is driving the market price of wholesale electricity down.

Agency Comments

The Department of Energy's Power Marketing Liaison Office provided written comments to GAO that reflect the views of Southeastern, Southwestern, and Western. These written comments and GAO's responses are discussed below and in chapters 2, 3, and 4, and appendix II.

In commenting on a draft of this report, the PMAs stated that they are following the law and congressional intent in their current repayment and accounting practices. They stated that congressional action would be needed to change PMA repayment and cost recovery practices. With regard to cost recovery, the PMAs agree that by law there are some power-related costs that are not fully recovered through rates. However, they believe that a distinction needs to be made between unrecovered (could be recovered in the future) versus unrecoverable (will never be recovered) costs and disagree with certain findings about unrecovered costs as discussed in the agency comments section of chapter 2. During its review, GAO noted that the PMAs were generally following applicable laws and regulations regarding cost recovery and financing of capital projects. However, determining whether the Congress should change PMA repayment and cost recovery practices was beyond the scope of GAO's review. GAO was requested to determine whether all power-related costs incurred as of September 30, 1995, had been recovered. The determination of whether unrecovered costs through this point in time will be recovered in the future, or whether all power-related costs should be recovered, was beyond the scope of this review.

The PMAs agree that certain unpaid investments are charged an interest expense that is less than Treasury's cost of borrowing at the time the investment was made. However, they believe GAO's methodology for calculating the financing subsidy is flawed and that it should not include the PMAs' flexible repayment terms as part of the calculation of the financing subsidy. GAO disagrees. As stated in chapter 3, GAO believes that there is a financing subsidy on the PMAs' appropriated debt because interest rates the PMAs pay do not fully recover the federal government's cost of funds. GAO believes that its methodology in calculating this financing subsidy reflects a reasonable approximation of the net cost of power-related financing to the federal government. This net cost includes both the interest differential at the time of the borrowing and the PMAs' flexible repayment terms for their appropriated debt.

The PMAs noted that they are not truly comparable to other utilities because of their unique characteristics and different mission. The PMAs agree that they are low cost producers of electricity but disagree with GAO's use of average revenue per kWh to make comparisons with other utilities. The PMAs stated that using average revenue per kWh to make such comparisons may mislead the report's readers about the magnitude and causes of the difference in cost between PMAs and other utilities. As stated in chapter 4, GAO believes that average revenue per kWh is a strong indicator of the PMAs' relative power production cost and competitiveness. GAO also believes that PMA customers are primarily concerned with production costs and resultant electricity rates. Given falling electricity rates and increasing competition, if the PMAs do not market low cost power, then they may not be able to recover all power-related costs. Therefore, GAO believes that its comparison of the differences in power production costs between PMAs and other utilities and the reasons for the differences are essential.

GAO discussed this report's contents with U.S. Army Corps of Engineers officials, including the Hydropower Coordinator and audit liaison representatives. They generally concurred with the contents of this report and provided oral comments, which GAO has incorporated into the final report, as appropriate. The U.S. Bureau of Reclamation, Department of the Interior, provided unofficial comments, which we incorporated into the final report, as appropriate. Official written comments were not received from the Bureau in time for publication of this report.

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Chapter 4 Federal Subsidies and Inherent Advantages of PMAs Result in Low-cost Power

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Abbreviations

AEAN	aggregate entry age normal
APPA	American Public Power Association
CSRS	Civil Service Retirement System
CVP	Central Valley Project
CWIP	construction-work-in-progress
DOE	Department of Energy
EEI	Edison Electric Institute
EIA	Energy Information Administration
F&WS	U.S. Fish and Wildlife Service
FASAB	Federal Accounting Standards Advisory Board
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FERS	Federal Employee Retirement System
FTE	full-time equivalent
GASB	Governmental Accounting Standards Board
IOU	investor-owned utility
IPP	independent power producer
KPMG	KPMG Peat Marwick LLP
kWh	kilowatthour
NERC	North American Electric Reliability Council
NRC	Nuclear Regulatory Commission
O&M	operating and maintenance
OMB	Office of Management and Budget
OPM	Office of Personnel Management
PMA	Power Marketing Administration
POG	publicly owned generating utility
PURPA	Public Utilities Regulatory Policies Act of 1978
SEPA	Southeastern Power Administration
SFAS	Statement of Financial Accounting Standards
SFFAS	Statement of Federal Financial Accounting Standards
SWPA	Southwestern Power Administration
UDC	ultimate development concept
WAPA	Western Area Power Administration

Introduction

Federal power marketing administrations (PMAs) are part of the Department of Energy (DOE). The five PMAs sell electric power within 34 states—to all states except those in the Northeast and upper Midwest. They sold about 3 percent of the nation's electric power output in 1994. Almost all of it is hydroelectric power generated by multiple-purpose dams built and operated by other federal agencies. The Chairman, Subcommittee on Water and Power Resources, House Committee on Resources, and the Ranking Minority Member, House Committee on Resources, asked us to review several issues relating to three of these PMAs—Southeastern, Southwestern, and Western. The primary focus of our review was to determine whether all power-related costs incurred through September 30, 1995, have been recovered through the PMAs' electricity rates; whether the financing for power-related capital projects is subsidized by the federal government and, if so, to what extent; and how PMAs differ from nonfederal utilities and the impact of these differences on power production costs. In addition, we were asked to provide information on Federal Energy Regulatory Commission (FERC) oversight of the PMAs.

PMAs Market Power Generated by Other Agencies

Nationwide, there are five PMAs—the three on which this report is focused, plus the Alaska Power Administration and the Bonneville Power Administration.[1] Established between 1937 and 1977,[2] PMAs sell electricity primarily on a wholesale basis with the legislated goal of encouraging widespread use of power at the lowest possible cost to consumers consistent with sound business principles. By law, they 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." PMAs helped make electricity available for the first time to many consumers who lived in rural areas.

PMAs generally control and operate power transmission facilities, but do not control or operate the facilities that actually generate electric power.[3]

[1]See Bonneville Power Administration: Borrowing Practices and Financial Condition (GAO/AIMD-94-67BR, April 19, 1994).

[2]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 four PMAs from the Department of the Interior to DOE.

[3]The Alaska Power Administration, which controls and operates two projects, is the one exception. Alaska's two projects are not multipurpose; they are operated to serve power needs only. Legislation has been enacted to sell the Alaska Power Administration to nonfederal entities.

These power generating facilities are controlled by other federal agencies—most often by the Department of the Interior's Bureau of Reclamation (Bureau) or the Department of the Army Corps of Engineers (Corps). The dams at which the power generating facilities are located also serve a variety of nonpower purposes, including flood control, irrigation, navigation, and recreation. The project must be operated in a way that balances all of these uses—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 Corps and the Bureau, which are called the "operating agencies."

Power-Related Appropriations to PMAs and to Operating Agencies Must Be Recovered Through Rates

Unlike most other federal agencies, PMAS are required by law to recover through rates funds appropriated for power-related costs. Funding for the three PMAS is generally through the annual appropriations process.[4] The PMAS receive annual appropriations and make both capital expenditures, such as for PMA-controlled transmission facilities, and operating and maintenance (O&M) expenditures. PMAS generally pay for these expenditures by requesting Treasury to cut checks on their respective appropriation accounts. The operating agencies also receive appropriations. The operating agencies allocate the portions of those appropriations that are used to fund power-related capital and O&M expenses to the PMAS for recovery from power rates.

The allocated portion 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" are allocated to the PMAS. These are capital costs and O&M expenses related not only to power production but to the dam'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 recover these appropriations through revenues generated from power sales. The Reclamation Project Act of 1939 and the Flood Control Act of 1944 require PMAS to set power rates at levels that are forecasted as adequate to recover costs. The Reclamation Project Act of 1939 requires that rates for electric power be adequate to recover the power-related share of construction costs, to include interest charged at a rate of not less than 3 percent. The act also requires recovery of annual O&M costs and

[4]The Fort Peck Project, Colorado River Storage Project, and Central Arizona Project have been legislatively authorized to use revolving funds to finance some types of expenditures. In addition, some projects use nonfederal (third-party) financing as a supplemental funding source, as discussed in chapter 4.

"other fixed charges as the Secretary deems proper." The Flood Control Act of 1944 requires that rates for electric power be adequate to recover the cost of "producing and transmitting such electric energy." Power-related capital costs are to be recovered "over a reasonable period of years."

These legislative provisions have been implemented by the Department of Energy in DOE Order RA 6120.2 (September 20, 1979, as revised on October 1, 1983). This order specifies that the total revenues of any project administered by a PMA must be sufficient to recover O&M costs in the year incurred, to recover federal investment in generation and transmission facilities within a 50-year period, and to recover capital costs allocated to completed Bureau of Reclamation irrigation facilities that are beyond the capability of irrigators to repay (also called "irrigation assistance"). Under the order, capital investments have a longer recovery period than O&M costs. PMAS are generally required to recover, without interest, appropriations used to fund O&M costs in the same year that the expenses are incurred. In contrast, the PMAS are required to recover appropriations that fund capital investments (which we refer to as appropriated debt[5]), with interest, over a specified repayment period. The recovery period is generally 50 years for assets used to generate power and 35 to 45 years for assets used to transmit power.

The order specifies that the adequacy of power revenues be tested by the preparation of an annual study, known as a "power system repayment study," which is submitted by the PMAS for approval to the Secretary of Energy. This study forecasts power-related capital and O&M costs that the PMAS will be required to recover in the future. It also forecasts revenues expected to be forthcoming under current rates. If the study projects that revenues will not be adequate to recover power system costs over the remainder of the repayment period, rates may be increased or other cost recovery actions may be taken.

During the year, PMAS generate revenues based on the rates they have established in accordance with the power repayment studies. The three PMAS bill customers for power sales. Southeastern's and Southwestern's customers generally make payments directly to a U.S. Department of Treasury "lock box" at a bank. The bank processes the account payments and transfers the cash to Treasury's General Fund, where it is categorized as miscellaneous receipts. To finance their operations, Southeastern and

[5]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 the Treasury

Southwestern request Treasury to cut checks on their respective appropriations accounts.

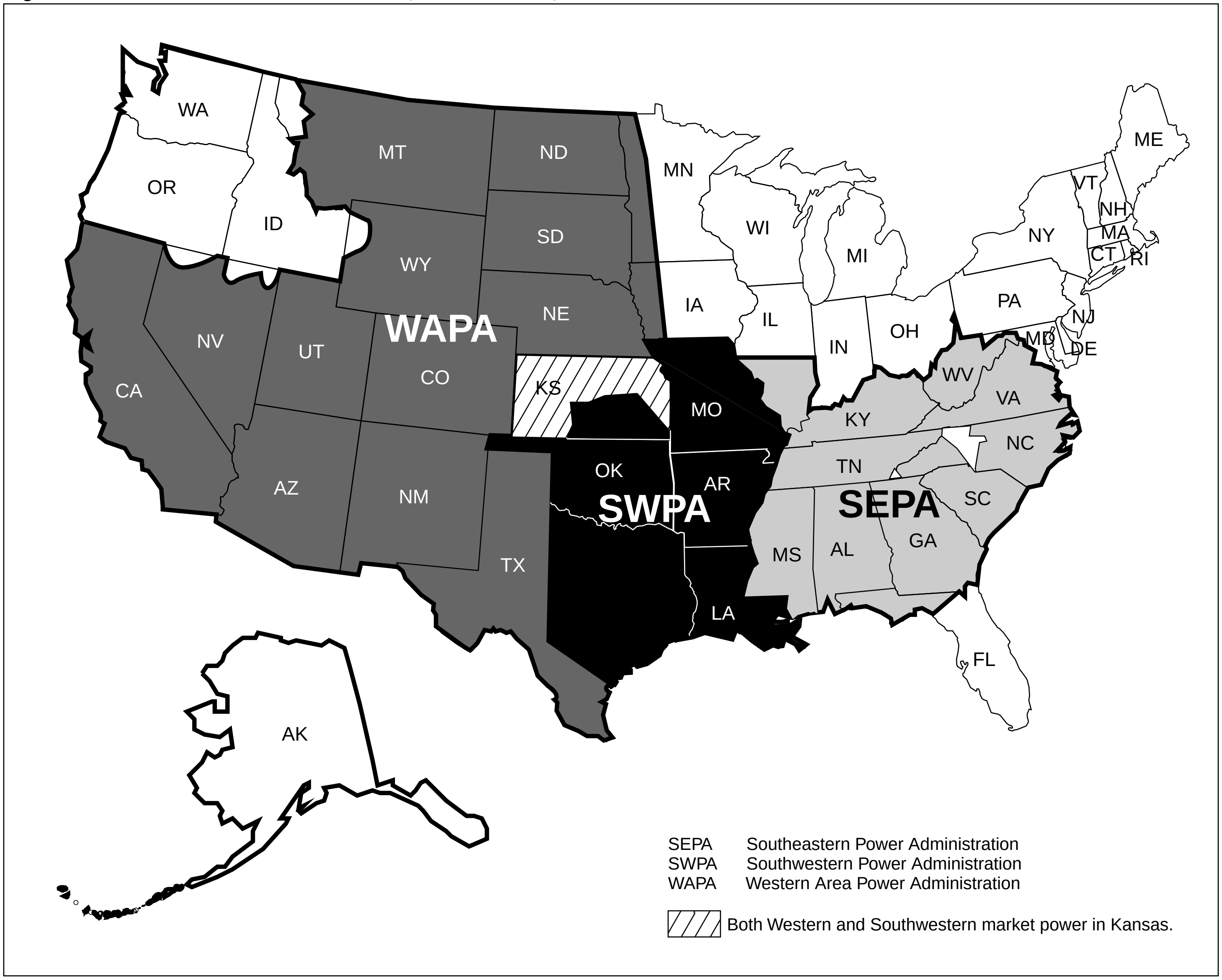
Western and its customers deposit collections directly to Treasury's "lock box" or federal reserve bank and then the receipts are posted to various Treasury accounts. Western either seeks annual appropriations from these accounts to finance its operations, or for certain accounts has the legal authority to spend funds without further appropriations. Those Treasury accounts include the Reclamation Fund; Colorado River Dam Fund; Boulder Canyon Project Fund; Falcon and Amistad Operating and Maintenance Fund; Central Valley Project Restoration Fund; Lower Colorado River Basin Development Fund; Upper Colorado River Basin Fund; and Colorado River Basins Power Marketing Fund. In this report, we refer to the recovery from revenues of power-related operating and maintenance appropriations and capital construction costs as a "repayment" or "payment" to Treasury, even though in most cases the PMAS do not write a check or otherwise transfer funds to Treasury.

Ideally, over the course of a year, collections received by Treasury will offset, or "repay," amounts appropriated to the PMAS and operating agencies for O&M expenses, as well as an amortized amount of capital construction costs. The PMAS, pursuant to the DOE Order, monitor expenses and revenues to ensure that power rates are sufficient to generate revenue to recover expenses. The DOE Order prescribes the sequence in which PMAS are to offset expenses with revenues as follows: (1) operations and maintenance, (2) purchased and exchanged power, (3) transmission services, and (4) interest. The remaining revenues are to be applied to the balance due on any payments of annual expenses that have been deferred (these are called "deferred payments," which the Order requires be repaid with interest) and then toward the repayment of capital investments. The Order also covers other subjects, including priority of capital cost repayment, interest rate calculation, and other PMA ratemaking and accounting criteria.

Role of Southeastern, Southwestern, and Western Area Power Administrations

Collectively, Southeastern, Southwestern, and Western Area Power Administrations market power in 30 states. (See figure 1.1.) In fiscal year 1995, they had total power sales of almost $1 billion. The power they sell is produced at 102 power plants built and run primarily by the Corps of Engineers or the Bureau of Reclamation.

Figure 1.1: Service Areas for Southeastern, Southwestern, and Western



Source: Developed by GAO from data provided by the PMAs.

The three PMAs differ substantially in size and revenue. (See table 1.1.) Western is the largest, accounting for more than four 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.

Table 1.1: Characteristics of Southeastern, Southwestern, and Western

PMA	Megawatt capacity	Number of power plants	Miles of transmission lines	Fiscal year 1995 revenues (in millions)
Southeastern	3,093	23	0	$159
Southwestern	2,051	24	1,380	114
Western	10,581	55	16,760	713

Source: Derived by GAO from the PMAs' audited financial statements and other PMA data for fiscal year 1995.

Collectively, the three PMAs are responsible for repaying about $5.4 billion of appropriated debt. (See table 1.2.) For 1995, the weighted average interest rate on this outstanding debt was 4.9 percent. (See chapter 3 for a more detailed discussion of appropriated debt balances and weighted average interest rates.)

Table 1.2: Appropriated Debt and Weighted Average Interest Rates

PMA	Appropriated debt as of 9/30/95 (in millions)	Weighted average interest rate for fiscal year 1995
Southeastern	$1,491	4.4%
Southwestern	686	2.9 %
Western	3,184[a]	5.5 %
Total	**$5,361**	**4.9%**

[a]Excludes $1.5 billion of irrigation debt stemming from capital costs related to completed irrigation facilities, for which no interest is charged. These irrigation costs are discussed in chapter 3. Includes Western's deferred payments.

Source: The PMAs' audited financial statements for fiscal year 1995 or material developed by GAO from other data provided by the PMAs.

Additional specific information about each PMA follows.

Southeastern. The Southeastern Power Administration was created in 1950 to market federal power on a wholesale basis. The 23 hydroelectric power plants from which Southeastern markets power are all operated by the Corps. About half of the plants (with more than 60 percent of the generating capacity) have been added since 1960. In 1995, Southeastern marketed power to 296 customers. In all, it sold about 6.8 billion kilowatthours (kWh)[6] of energy. The percentage of cost allocated to power by the Corps averages about 69 percent and ranges by facility from about 45 percent to about 81 percent. Because it has no transmission lines of its own, it has no transmission-related investment costs to recover.

Southwestern. The Southwestern Power Administration was created in 1943. The 24 hydroelectric power plants from which Southwestern markets wholesale[7] federal power are all operated by the Corps. Slightly less than two-thirds of the plants (and 56 percent of the capacity) have been added since 1960. In 1995, Southwestern marketed power to 95 customers, selling about 7.7 billion kWh of energy. The percentage of cost allocated to power by the Corps averages about 35 percent and ranges by facility from about 21 percent to about 68 percent. Southwestern's investment in transmission facilities as of September 30, 1995, was about $126 million.

Western. The Western Area Power Administration was created in 1977. The establishing legislation transferred power marketing responsibilities and transmission assets previously managed by the Bureau of Reclamation to Western. Western markets power, on a wholesale[8] basis, from 55 hydroelectric power plants. The Bureau operates 45 plants, the Corps operates 6, and the remaining 4 are operated by three other organizations.[9] Western also markets the federal government's share of electricity generated by the coal-fired Navajo Generating Station in Arizona. In 1995, Western marketed power to 546 customers, selling about 32.8 billion kilowatthours of energy. The percentage of cost allocated to power by the operating agencies for three large projects that Western is responsible for averaged about 50 percent. These three projects accounted for about 83 percent of Western's 1995 revenues. The individual cost allocations for the three projects were 21 percent, 46 percent, and 84 percent.[10] Western's investment in transmission facilities as of September 30, 1995, was about $2.1 billion.

[6]A kilowatthour is 1,000 watt hours. A watt hour is equal to 1 watt of power applied for 1 hour.

[7]A small percentage of Southwestern sales are to end users.

[8]A small percentage of Western sales are to end users.

[9]Two plants are operated by the Department of State's International Boundary and Water Commission. The Provo Water User's Association and the California Department of Water Resources each operate one plant.

[10]Extensive calculations would be required to determine the percentage of cost allocated to power for all projects. As such, we limited our analysis to the three largest projects.

Oversight of PMAs

Each PMA is led by an administrator, who is appointed by the Secretary of Energy. The administrator is authorized to make decisions regarding PMA operations, subject to the supervision and direction of the Secretary. DOE oversight includes approving PMA budgets as part of DOE's annual federal budget process, establishing each PMA's personnel limit, and giving interim approval to rate adjustments that the PMA recommends. The PMA financial officers typically participate in the determination of rates.[11] The final approval of PMA rates is the responsibility of FERC. Appendix VI discusses FERC oversight in detail.

The Department of Energy's Office of Inspector General has programmatic oversight responsibility for the PMAs, as well as oversight of the PMAs' financial accountability.[12] DOE Order RA 6120.2 calls for the PMAs to prepare annual reports containing audited financial statements. The Inspector General retains Independent Public Accountants to perform annual audits of these financial statements.

Legislative Changes Result in Competitive Wholesale Electricity Market

Increasing competition in the wholesale electricity market could have a major impact on the PMAs. Historically, investor-owned utilities (IOUs) and other electricity providers have operated as regulated monopolies. IOUs typically are required to provide electric service to all customers within their power service areas in exchange for exclusive service territories. To serve customers, utilities incur costs for building new generating plants and operating the power system. Through electricity rate charges, IOUs generally recover all costs incurred plus a regulated rate of return.

Several key laws have resulted in an increasingly competitive electricity market. 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 federal and state regulations. Called "nonutility generators" or "independent power producers" (IPPS),[13] these entities typically use new technologies, such as

[11] Senior financial managers at Southeastern and Southwestern are involved in rate-setting. However, Western's Chief Financial Officer is not involved.

[12] In addition, the Department of the Interior's Office of the Inspector General has oversight responsibility pertaining to the Bureau of Reclamation, and the Department of Defense's Inspector General has oversight responsibility pertaining to the Corps of Engineers.

[13] IPPs, which are firms that produce electric power to be sold at wholesale rates, are not considered utilities because they do not produce power for a service area and do not engage in transmitting or distributing power.

cogenerating plants[14] or natural gas-fired generation units, to generate power. The National Independent Energy Producers[15] estimated that, at the end of 1995, IPPs accounted for about 8 percent of the total generating capacity in the United States.

IPPs pose a direct competitive threat to PMAs, IOUs, and other utilities, in part because they can build generation facilities near large industrial or municipal customers and sell power to these customers for a lower rate than the established utility. In addition, recent technological advances have significantly increased the efficiency of natural gas-fired generation units. The growth and increased efficiency of IPPs have placed downward pressure on wholesale electricity rates.

The Energy Policy Act of 1992 promoted increased competition in the electricity market. The act encouraged additional wholesale suppliers to enter the market and opened the transmission of electricity 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—referred to as wheeling of power. Fees are paid to the transmitting utility for use of its system. Under the act's provisions, FERC can compel a utility to transmit electricity generated by another utility into its service area for resale. More recently, FERC has issued a final rule implementing this provision of the act. DOE has directed the PMAs to comply with the intent of the act and FERC's rule. According to Western and Southwestern, they have always operated with a policy of open access to their transmission systems on a first-come, first-served capacity available basis. As a result of the increased competition, FERC expects wholesale and retail electricity rates to drop. Increased competition may impact the PMAs' status as a low cost supplier.

Objectives, Scope, and Methodology

The objectives of this report were to determine (1) whether all power-related costs incurred through September 30, 1995, have been recovered through the PMAs' electricity rates (chapter 2), (2) whether the financing for power-related capital projects is subsidized by the federal government and, if so, to what extent (chapter 3), and (3) how PMAs differ from nonfederal utilities and the impact of these differences on power production costs (chapter 4). Additional information on our objectives, scope, and methodology is in appendix I. This appendix includes detailed

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

[15]The National Independent Energy Producers is a trade association representing many nonutility generators of electricity and IPPs.

explanations of the calculations of various estimates used in the report, as well as a list of the various organizations and groups we contacted.

When appropriate, we used audited numbers from the PMAs' 1995, 1994, and earlier annual reports. We conducted our review from January 1996 through September 1996 in accordance with generally accepted government auditing standards. We requested written comments on a draft of this report from the three PMAs, the Department of Energy, and the operating agencies. Only the PMAs provided written comments in time for publication in this report. These comments are evaluated and reprinted in appendix II.

Rates Do Not Recover All Power-related Costs

Some costs related to producing and marketing federal hydropower are not being recovered through power rates by the three PMAs. We identified five main power-related activities for which costs are not fully recovered. First, the three PMAs do not recover the full costs to the federal government of providing Civil Service Retirement System (CSRS) pensions and postretirement health benefits for current PMA employees and operating agency employees engaged in producing and marketing the power sold by the PMAs. Second, there are construction projects for which the three PMAs might not recover costs from power customers. Third, power-related construction and O&M expenses assigned to incomplete irrigation facilities at Pick-Sloan will likely not be recovered. Fourth, certain costs for environmental mitigation have been legislatively precluded from cost recovery. Finally, Western had unrecovered O&M and interest expenses as of September 30, 1995, related to certain projects. Taking into consideration all these categories of unrecovered costs we identified, we estimated that the amount of unrecovered costs for fiscal year 1995 was about $83 million. We estimated that the cumulative amount of these unrecovered costs, as of September 30, 1995, could be as much as $1.8 billion. It is important to note that the PMAs are generally following applicable laws and regulations regarding cost recovery.

Recovery of Some Costs Has Not Been Required

The Reclamation Project Act of 1939 and the Flood Control Act of 1944, as discussed in chapter 1, generally require the recovery through power rates of the costs of producing and marketing federal hydropower. However, these acts do not specify which costs are to be recovered. The Reclamation Project Act refers to the recovery of “annual operation and maintenance” costs and “other fixed charges as the Secretary deems proper.” The Flood Control Act refers to the recovery of the costs associated with producing and transmitting electricity from federal power projects. Neither act defines its terminology.

Recovery of power-related costs has been implemented by the Secretary of Energy through DOE Order RA 6120.2.[1] The DOE order states that all costs of operating and maintaining the power system, as well as the costs of transmission, should be included in rates. The order does not define operating and maintenance costs. Given the flexibility this lack of specific guidance provides, the PMAs have interpreted it to exclude certain costs from rates.

[1]Although the office that wrote the order has been abolished and the order has not been updated since October 1983, the three PMAs still consider it to be DOE’s most authoritative guidance on PMA financial reporting and rate-setting.

To define the full costs associated with producing and marketing federal hydropower, we referred to Office of Management and Budget (OMB) Circular A-25, "User Fees," which provides guidance for federal agencies to use in setting fees to recover the full costs of providing goods and services.[2] DOE Order RA 6120.2 does not adopt this guidance or otherwise refer to OMB Circular A-25. Nevertheless, the circular does offer a definition of full costs that is useful in identifying power-related costs that the PMAs do not now recover through power rates. OMB Circular A-25 defines full costs as all direct and indirect costs of providing the goods or service. This definition is consistent with that contained in federal accounting standards recommended by the Federal Accounting Standards Advisory Board (FASAB) and adopted by GAO, OMB, and Treasury.[3] The FASAB standards define the full cost of an entity's output as ". . . the sum of (1) the costs of resources consumed by the segment that directly or indirectly contribute to the output, and (2) the costs of identifiable supporting services provided by other responsibility segments within the reporting entity, and by other reporting entities." Applying the definitions of "full cost" used in OMB Circular A-25 and federal accounting standards indicates that the full cost of the electricity sold by the PMAs would include all direct and indirect costs incurred by the operating agencies to produce the power, the PMAs to market and transmit the power, and any other agencies to support the operating agencies and PMAs.

Investor-owned and publicly-owned utilities generally must recover the full cost of producing power through rates. A discussion of relevant private industry accounting and cost recovery practices is in chapter 4.

It is important to note that we did not assess the reasonableness of the methodologies used in developing the operating agency cost allocation formulas that are established for each project. To more fully assess whether PMA electricity rates include all power-related costs would require an analysis of the reasonableness of these allocations. If the allocation formulas were not reasonable, it could result in a substantial over- or under-allocation of costs by the operating agencies to the PMAs.

[2]OMB Circular A-25's purpose is to implement a law commonly known as the User Fee Statute. However, its guidance may be used by agencies in setting fees authorized by other laws to the extent it does not conflict with the requirements of those laws.

[3]FASAB Statement of Federal Financial Accounting Standards (SFFAS) no. 4, Managerial Cost Accounting Concepts and Standards for the Federal Government, June 1995.

Pension and Postretirement Health Benefits Are Not Fully Recovered

The three PMAs do not recover the full costs to the federal government of providing postretirement health benefits and CSRS pensions for current PMA employees and operating agency employees engaged in producing and marketing the power sold by the PMAs. The employee and the employing agency both contribute annually toward the costs of the future CSRS pension benefits. Since the employee and agency contributions toward CSRS pensions are less than the full cost of providing the pension benefits, the federal government must, in effect, make up the funding shortfall. In addition, neither the agency nor the employee pays the federal government's portion of postretirement health benefits, which will eventually be paid by the general fund of the Treasury. For 1995 alone, these unrecovered costs for the three PMAs were an estimated $16.4 million.[4] The cumulative unrecovered CSRS pension and postretirement health benefit costs for the three PMAs totaled an estimated $436 million as of September 30, 1995. According to Office of Personnel Management (OPM) officials, pensions for employees covered by the Federal Employees Retirement System (FERS) are fully funded each year and cumulatively, so there are no relevant unrecovered costs. See appendix I for a discussion of our methodology for computing unrecovered pension and postretirement benefit costs.

As with all other federal agencies, the full cost of CSRS pension benefits is not paid by the PMAs or the operating agencies. As required, CSRS employees and the agency each pay a fixed percentage—7 percent—of the employee's salary to offset future pension costs. However, this combined contribution does not cover the full cost of the employee's future pension benefits, which amounted to more than 25 percent of salary as of September 30, 1995. Thus, the annual funding shortfall is more than 11 percent of every CSRS employee's salary.[5] The annual funding shortfall associated with 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 annually.

The full cost of the federal government's portion of postretirement health benefits (for both CSRS and FERS employees) is likewise not paid by federal agencies, including the PMAs and operating agencies, during the period of

[4]Our analyses covered pension and postretirement health benefits for current employees only; the costs associated with retirees were not considered because the actuarial information needed to do so was not readily available from OPM.

[5]Public Law 99-335, the statute which established FERS, requires that when the budget authority in the retirement fund for CSRS is exhausted, automatic annual appropriations will be made to amortize the shortfall over 30 years. For more detail on the funding status of FERS and CSRS, see Public Pensions: Summary of Federal Pension Plan Data (GAO/AIMD-96-6, February 16, 1996).

the beneficiaries' employment. OPM estimates that almost $2,000 per employee would need to have been contributed in fiscal year 1995 to cover each employee's postretirement health benefit costs earned. However, no fund has been established to accumulate assets to pay for these future benefits, which will eventually be paid for by the federal government. In contrast to the situation regarding CSRS pensions, the annual funding shortfall associated with postretirement health benefits will not be eliminated as CSRS employees are replaced by FERS employees, since it is an entirely separate benefit program.

OMB Circular A-25 specifically includes all funded or unfunded retirement costs not covered by employee contributions in its definition of full cost. In addition, beginning in fiscal year 1997, Statement of Federal Financial Accounting Standards (SFFAS) no. 5[6] requires federal agencies to record the full cost of pension and postretirement health benefits in annual financial statements. Private sector accounting standards have required similar reporting for pensions[7] beginning in 1987 and postretirement health and other benefits[8] beginning in 1993. IOUs have adopted SFAS no. 87 and SFAS no. 106 for accounting purposes and in most instances for rate-setting.

Annual and Cumulative Unrecovered Costs

Based on our analysis of the estimated number of full-time equivalent (FTE) positions involved in producing and marketing the power sold by the three PMAs, and information provided by OPM, we estimated that the fiscal year 1995 unrecovered pension and postretirement health benefits totaled about $10.3 million and $6.1 million, respectively.[9] For pensions, about $7.3 million of the unrecovered costs (70 percent) related to personnel involved in producing and marketing the power sold by Western, while about $1.7 million (16 percent) and $1.4 million (14 percent) related to Southeastern and Southwestern, respectively. For postretirement health benefits, about $4.2 million of the unrecovered costs (69 percent) related to Western, while about $1.1 million (18 percent) and $786,000 (13 percent) related to Southeastern and Southwestern, respectively. These are the amounts that would have been necessary to fully recover CSRS pensions and postretirement health benefits earned in fiscal year 1995

[6]Statement of Federal Financial Accounting Standards (SFFAS) no. 5, Accounting for Liabilities of the Federal Government.

[7]Statement of Financial Accounting Standards (SFAS) no. 87, Employers' Accounting for Pensions.

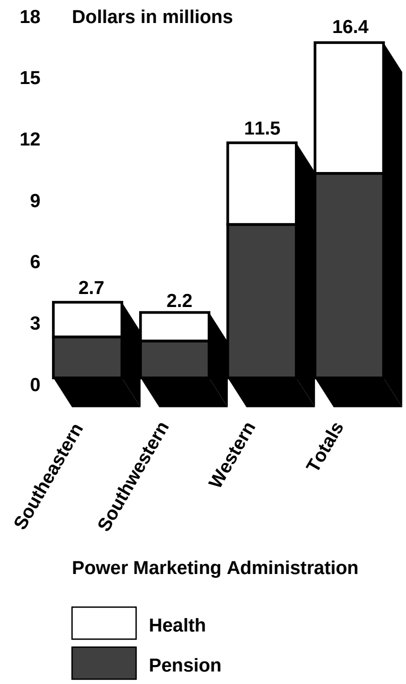
[8]Statement of Financial Accounting Standards (SFAS) no. 106, Employers' Accounting for Post-retirement Benefits Other Than Pensions.

[9]The individual amounts attributable to the PMAs may not add to totals due to rounding.

for current employees of the three PMAs and operating agency employees involved in power production and marketing. These costs, which are not recovered by the PMAs through power rates, are shown in figure 2.1. More detailed information regarding these unrecovered costs can be found in appendix III.

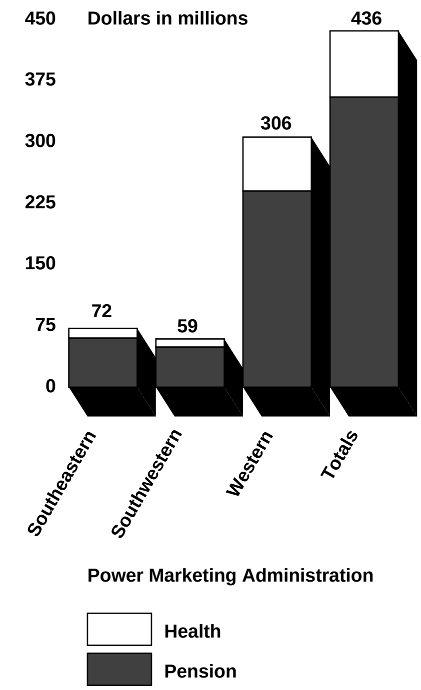
Based on our analysis of estimated FTEs associated with producing and marketing power and information provided by OPM, we estimated that the cumulative unrecovered costs for pension and postretirement health benefits as of September 30, 1995, are $355 million and $81 million, respectively. For pensions, about $250 million of the cumulative unrecovered costs (70 percent) related to personnel involved in producing and marketing the power sold by Western, while about $57 million (16 percent) and $48 million (14 percent) related to Southeastern and Southwestern, respectively. For postretirement health benefits, about $56 million of the cumulative unrecovered costs (69 percent) related to Western, while about $14 million (18 percent) and $10 million (13 percent) related to Southeastern and Southwestern, respectively. The cumulative unrecovered costs for current employees are depicted in figure 2.2. More detailed information regarding the cumulative unrecovered costs can be found in appendix III.

Figure 2.1: Estimated 1995 Unrecovered Pension and Postretirement Health Benefits



Source: GAO estimates based on information provided by the PMAs, operating agencies, and OPM.

Figure 2.2: Estimated Cumulative Unrecovered Pension and Postretirement Health Benefits as of September 30, 1995



Note: Total column may not add due to rounding.

Source: GAO estimates based on information provided by the PMAs, operating agencies, and OPM.

Some Project Construction and Interest Costs Are Not Being Recovered

There are construction costs that the three PMAs might not recover from power customers. In two cases, the Richard B. Russell and Harry S. Truman Projects, costs are not currently being recovered because the power-generating projects have not operated as designed. In two other cases, the Washoe and Mead-Phoenix Projects, the tenuous financial condition of the projects raises questions about whether power costs will be recovered. In another case, power-related costs associated with a Western abandoned transmission line incurred before 1969 have not been included in rates and there is a chance that these costs may never be recovered from power customers.

Russell Project

To date, about one-half of the cost of constructing the Richard B. Russell Project,[10] which is located on the Savannah River between Georgia and

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

South Carolina, has been excluded from Southeastern's rates to power customers because the project has never operated as designed. In addition, interest associated with the pumping units is not paid to Treasury each year.[11] Instead, interest—$25.6 million for fiscal year 1995—is capitalized and added to the construction-work-in-progress (CWIP) balance annually. If the project never operates as designed, it is uncertain whether the federal government will be able to fully recover these construction and capitalized interest costs.

Positioned between two existing dams, the Russell Project was built virtually exclusively for the generation of hydropower. Ninety-nine percent of the original construction costs and 93 percent of annual O&M expenses associated with the Russell Project are tentatively 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. The last of the four conventional units came on-line in 1986, and the costs associated with those units went into the customers' rate base. However, because of litigation over excessive fish kills, the four pumping units, which 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, where interest has been accruing, and have not been included in rates. Southeastern's financial statements show about $488 million in CWIP as of September 30, 1995, all of which is for construction costs and capitalized interest related to the Russell Project. Of the $488 million related to Russell, an estimated $338 million was for construction costs and $150 million for capitalized interest.

Southeastern continues to classify as CWIP the $488 million of costs related to Russell's pumping units, even though construction on those units was completed in 1992 and associated litigation and environmental testing have been ongoing since May 1988. According to its fiscal year 1995 financial statements, Southeastern follows SFAS no. 71, Accounting for the Effects of Certain Types of Regulation. In situations similar to Russell's, if the costs were deemed allowable by the regulator, private entities

[11]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.

following SFAS no. 71 would transfer the amount from CWIP to a regulatory asset account and begin recovering costs. Under DOE Order RA 6120.2 guidance, however, Southeastern may not be required to recover the costs of Russell's pumping units through rates as long as the units are nonoperational. Southeastern officials believe that the litigation over the pumping units will be resolved in Southeastern's favor, the pumping units will be allowed to operate commercially, and the costs associated with them will be recovered through rates. However, if the four pumping units are never allowed to operate commercially, it is unclear whether the costs associated with them—about $488 million as of September 30, 1995—will be recovered through power rates.

Truman Project

A similar situation exists at the Harry S. Truman Dam and Reservoir, which is located in the Osage River in Missouri.[12] 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 recreation) in November 1979. The in-service dates for hydropower generating units range from January 1980 to September 1982. Total power-related construction costs were about $158 million as of the end of fiscal year 1995.

The Truman Project has six generating units, also designed to operate as pumping units, which provide 160,000 kilowatts of capacity. However, because of excessive fish kills 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 Southwestern's power rates the costs associated with the units that have not been used commercially. The Corps prepared an interim cost allocation for this project that accounted for the fact that the project was not fully operational. Southwestern petitioned FERC to have the cost of the nonproducing portion of the assets deferred from inclusion in power rates until it 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, which consists

[12]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.

of capital construction costs and capitalized interest, has been deferred from recovery through power rates, reducing the total to be repaid from $158 million to $127 million.[13] 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 if the Harry S. Truman facility operates as designed.

Through 1994 the Corps calculated the interest expense associated with hydroelectric projects related to Southwestern. Interest expense was based on the entire power-related construction costs of these projects. Southwestern was therefore paying interest on the $31 million Truman deferral.

Beginning in fiscal year 1995, Southwestern and the other PMAs began calculating the power-related interest expense on the operating agency projects. In 1995, Southwestern's calculation of interest expense for the Truman project excluded interest associated with the $31 million Truman deferral. About $930,000 in interest associated with the Truman deferral was therefore not paid and was excluded from Southwestern's rates. Southwestern officials have acknowledged the error and said that the 1995 underpayment of interest will be corrected in fiscal year 1996.

Washoe Project

The Washoe Project (Stampede Dam) is not generating sufficient revenue to cover annual power-related O&M expenses and interest and repay the federal investment. The 3,650 kilowatt power plant for the Stampede Dam was completed in 1987, and power sales began in 1988. Since the project began producing power, it has only generated sufficient revenue to cover a portion of its annual O&M expenses and has been unable to make any annual interest payments. In addition, the project has not generated enough revenue to repay any of the project's appropriated debt. Since 1988, the project has deferred about $3.9 million in O&M and interest expense payments. As of September 30, 1995, the outstanding unpaid federal investment in the project was $8.9 million.

According to Western, the project has not been able to recover the costs of producing power because the project: (1) has construction costs that are high in relation to other utilities, (2) has not been able to find customers to

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

purchase the power at a rate that would recover the full cost of producing the power, (3) began producing power in the first year of a 7-year drought, and (4) prior to 1992, lacked the transmission service to wheel power to customers interested in buying the power. Western officials project that a permanent rate increase of almost 500 percent would be necessary to recover the annual costs. In January 1996, Western projected that it would have to sell its Washoe power at a rate of at least 11 cents per kilowatthour (kWh) to cover annual O&M expenses (excluding depreciation), interest charges, and debt repayments; however, in fiscal year 1995, the project was selling power at about 2 cents per kilowatthour. According to Western's fiscal year 1995 annual report: "Based on current conditions, it is unlikely the project will be able to generate sufficient revenues to repay the Federal investment." For the same reasons, we believe that the Washoe Project is unlikely to generate sufficient revenue to repay all O&M and interest expenses.

During fiscal year 1994, Western negotiated a contract to sell some Washoe power to the U.S. Fish and Wildlife Service (F&WS). The project's authorizing legislation specifies that the cost of facilities for the development of the fish and wildlife resources of the project area, including the O&M costs, shall be nonreimbursable. Western classified the cost of power sold to F&WS as nonreimbursable, thereby reducing the amount of construction and O&M costs that must be repaid to Treasury by the Washoe Project. Western believes the project can become more financially viable by reclassifying a portion of the project's costs as nonreimbursable. However, we believe this action just shifts the responsibility for recovering the project's costs from the ratepayers to the federal government, and does not reduce the actual costs of producing the power. Therefore, we believe this action does not significantly improve the prospects of the project being able to generate sufficient revenue to cover all power-related capital costs or O&M and interest expenses.

Western's Mead-Phoenix Transmission Line

Another project with questionable financial viability is the Mead-Phoenix Transmission Line,[14] a recent addition to the Pacific Northwest-Pacific Southwest Intertie Project intended to increase power transmission capability between the Pacific Northwest and Pacific Southwest. This

[14]The Mead-Phoenix Transmission Line is a recent addition to the Intertie Project. Upon completion, the Mead-Phoenix Line, in conjunction with the Mead-Adelanto Line, will provide additional power transmission capability between central Arizona, southern Nevada, and southern California. The Mead-Phoenix Line consists of 256 miles of 500-kV transmission line that runs from Phoenix, Arizona, through Mead Substation near Boulder City, Nevada, and on to Marketplace switching station, also in southern Nevada. Our discussion of financial viability relates only to Western's portion of the Mead-Phoenix addition.

transmission project was a joint venture between Western and 13 other participants and began operation in April 1996. Western's share of the total project's costs is about 34 percent. According to Western officials, Western's portion of the cost of the project, including capitalized interest, is expected to be about $94.1 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 proposed 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. A Western official told us that during its first few months of operation in 1996, the project has not generated sufficient revenues to cover all O&M and interest expenses. However, Western is confident that sufficient revenues will be raised to recover annual O&M and interest expenses.

In recent testimony before the Subcommittee on Water and Power Resources, House Committee on Resources,[15] Western's Administrator said that it is aggressively marketing the remainder of the line's capacity. The Administrator indicated that if the project does not achieve the level of sales assumed in developing the transmission charges, Western will initiate a new rate process to ensure the recovery of project costs. If Western is unable to find customers for all of its capacity, it is uncertain whether market forces will allow it to increase its rates enough to generate sufficient revenue to recover annual O&M and interest expenses or appropriated debt.

Western's Abandoned Transmission Line

Another example of an unrecovered power-related cost is an abandoned transmission line that has incurred costs of about $14.5 million, which Western has not included in power rates. According to the Bureau, the transmission line, which was planned to be the direct current portion of the Pacific Northwest-Pacific Southwest Intertie Project, was abandoned because of sporadic funding. Because the project has not provided any benefits to project customers, the ratepayers recently requested that Western seek authority through the budget cycle to have about $11.1 million of the cost of the abandoned transmission line declared nonreimbursable. If Western was granted such authority, the power customers would not be required to recover these costs through rates. However, Western recently asserted that it (1) does not plan to request authority to declare any of the costs of this project as nonreimbursable

[15]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 (2) plans to include the costs of the abandoned transmission line in its power repayment study for recovery.

In addition to not repaying the construction costs, Western has not paid the federal government any interest on this investment since construction began on the project in 1965. In fiscal year 1995, if Western had paid interest at the rate that applied when construction began—3 percent—it would have paid about $435,000 in interest on the $14.5 million. We estimate that if Western had begun repaying the annual interest expense on the project costs when construction was discontinued in 1969, it would have paid the federal government about $6.4 million in annual interest payments over the 26-year period from 1969 to 1996. The potential unrecovered costs as of the end of fiscal year 1995 are about $20.9 million.

Because the cost of the abandoned transmission line has not been included in rates since construction was discontinued over 26 years ago, we believe doubt exists about whether these costs will ever be included in rates. However, if these costs are ever taken into rates, it is not clear whether interest will be recovered from the time construction was discontinued in 1969 through when the costs are included in rates. It is also unclear whether the 50-year repayment period will begin in 1969 or when the costs are actually included in the power repayment study. In addition, Western did not disclose which rate-setting system would absorb these costs. Western officials were unable to clarify these issues. The cost to the federal government of Western's decision to delay resolution of cost recovery for the abandoned transmission line will depend on how it decides to address these issues.

Costs Assigned to Incomplete Irrigation Facilities Will Likely Not Be Recovered

As of September 30, 1994, about $454 million of the federal investment in the capital costs for hydropower facilities and water storage reservoirs of the Pick-Sloan Missouri Basin Program (Pick-Sloan) had been allocated to authorized irrigation facilities that are incomplete and infeasible. Western is currently selling electricity to its power customers that would have been used by the irrigators had the irrigation facilities been completed. If these costs had been allocated based on the actual use of the hydropower facilities and water storage reservoirs, the costs would have been allocated primarily to power and repaid through electricity rate charges within 50 years, with interest.

If all of the irrigation facilities were to be completed as originally planned, the above capital costs would be repaid without interest primarily by power customers.[16] However, since all but one of these irrigation facilities are not expected to be completed, the capital costs assigned to these facilities will not be repaid unless Congress approves a change in the cost allocation methodology used to distribute costs to the various program purposes, or deauthorizes the incomplete irrigation facilities. However, any changes between the program's power and irrigation purposes may also 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.

In addition, interest is not being paid on the $454 million. Using the 3 percent interest rate in effect for power projects when construction began, we estimate that lost interest payments to Treasury amounted to about $13.6 million for fiscal year 1995.

The federal investment in the Pick-Sloan Program will continue to increase because of renovations and replacements. The capital costs assigned to the incomplete irrigation facilities will also continue to increase because of the cost allocation methodology, which is based on original agreements reached decades ago that anticipated that all irrigation facilities would be completed as planned. For example, in our May 1996 testimony,[17] we noted that the capital costs assigned to irrigation facilities increased about $37 million between fiscal year 1987 and fiscal year 1994, an average annual increase of nearly $5 million. Therefore, unless Congress approves a change in the cost allocation methodology used to assign capital costs to the various program purposes, ongoing power-related capital costs will continue to be assigned to the incomplete irrigation facilities and will likely not be recovered through rates.

Annual O&M expenses that otherwise would have been allocated to power and repaid from electricity rates have also been allocated to the incomplete irrigation facilities. Since 1987, Western has adjusted the Corps' allocated annual O&M expenses because the two agencies interpret

[16]Reclamation law 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 is guided by its implementing regulations, administrative decisions of the Secretary of the Interior, 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).

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

specific legislation[18] differently. As of September 30, 1995, about $13.7 million ($15.3 million in constant 1995 dollars) of the Corps' power-related O&M expenses had been allocated to incomplete irrigation facilities. The annual adjustments have ranged from a low of $1.1 million in fiscal year 1987 to a high of $2.1 million in fiscal year 1995. If these expenses had been allocated to power, they would have been included in Western's annual O&M expenses and recovered through electricity rates.[19]

Certain Environmental Mitigation Costs Are Legislatively Exempt From Recovery

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 are legislatively excluded from Western's power rates. For the Shasta Dam, these costs totaled $9.7 million and $5.4 million in 1995 and 1994, respectively. For the Glen Canyon Dam, these costs totaled $13.9 million and $12.5 million in 1995 and 1994, respectively. The total cumulative unrecovered environmental costs for the two projects was about $134.3 million ($152.5 million in constant 1995 dollars) as of the end of fiscal year 1995.

Certain environmental costs incurred at the Shasta Dam were exempted from recovery by the 1991 Energy and Water Development Appropriations Act. The act included a provision stating that any increase in purchased power cost incurred by Western after January 1, 1986, that resulted from bypass releases for temperature control purposes related to preservation of fisheries in the Sacramento River, not be allocated to power. According to Western, the bypass releases at Shasta will cease when construction of a Temperature Control Device is completed. Western expects this device to be in service by December 1996.

Similarly, certain costs of mitigating the environmental impact of fluctuating river flows at the Glen Canyon Dam were exempted from recovery by the Grand Canyon Protection Act of 1992. The purpose of the act was to "protect . . . and improve the values for which Grand Canyon National Park and Glen Canyon National Recreation Area were

[18]The McGovern Amendment to the 1977 Department of Energy Organization Act precludes any changes to the cost allocation methodology used by the Pick-Sloan Program without prior congressional approval. The Corps changed from the "ultimate development concept" (UDC) to the "current use" costs allocation methodology to allocate its annual O&M expenses to the various dam purposes. Since this change occurred after the passage of the McGovern Amendment and did not receive congressional approval, Western concluded that the Corps should have continued to use the ultimate development concept method to allocate O&M expenses. Western has adjusted the Corps' annual O&M expenses to reflect the ultimate development concept methodology that was used prior to 1987 and has presented the adjusted costs in its financial statements.

[19]In 1990, the Pick-Sloan Program did not generate sufficient revenues to repay its O&M expenses. The O&M expenses for this year were recorded as interest bearing debt and repaid in fiscal year 1995.

established." The act states that certain costs of environmental impact studies related to Glen Canyon Dam are not to be paid for by power customers. The act includes a provision that the above costs could become the responsibility of the power customers under certain circumstances. According to Western, sufficient data does not exist to determine whether the overall provisions of the act would result in a future obligation by the power customers. Western plans to reflect any future obligations related to these costs in the period in which such obligations become evident.

Certain Operating and Maintenance and Interest Expenses Are Not Yet Recovered by Western

Since fiscal year 1975, Western has deferred O&M and/or interest payments on 12 projects that are supposed to be repaid annually. Under DOE Order RA 6120.2, deferred O&M and interest payments are to be repaid the following year, with interest, at DOE policy rates,[20] before repayment of appropriated debt. In effect, the federal government extends an interest bearing loan to the PMAS in the amount of the deferred payments. The balance of Western's deferred payments outstanding at the end of fiscal year 1995 was about $196 million. This balance decreased from about $250 million at the end of fiscal year 1994 as Western repaid about $54 million in fiscal year 1995.[21] The bulk of the balance outstanding—almost $131 million—was associated with the Pick-Sloan Program. The remaining balance was associated with eight other projects. According to Western, the deferred payments have occurred primarily because of extended drought conditions. As a result of the deferred payments, many of the projects' firm power rates have been raised by Western. For example, Western stated that the composite firm power rate at the Pick-Sloan Program has increased approximately 75 percent since the start of drought conditions in 1988. Western attributes about half of the increase to the drought and the increased interest expense associated with the deferred payments and the failure to repay outstanding appropriated debt. Although Southeastern and Southwestern have deferred O&M and interest expense payments, both had repaid the amounts, with interest, prior to September 30, 1995.

Because of the PMAS' reliance on hydropower to generate electricity, the PMAS' annual revenue is unpredictable and varies from year to year. As a result, the DOE order that specifies the terms PMAS must follow to repay their federal investment was designed with the variable revenue

[20]For a description of DOE policy rates, see chapter 3.

[21]The $54 million is a net amount. Some projects paid all current year expenses and also reduced their balances of outstanding deferred payments, while other projects deferred current year payments totaling about $765,000 in fiscal year 1995.

characteristics of hydroelectric systems in mind. The DOE order allows the PMAS to vary the repayment of their federal investments and miss interest and/or O&M expense payments in years when revenue is not sufficient to cover these costs. However, the DOE regulations require the PMAS to record deferred annual payments as liabilities[22] on their financial statements and to repay these deferred payments plus interest in future years before any principal payments are made on the outstanding federal investment.

The amount and frequency of deferred payments over the last 20 years have varied among the three PMAS. Since fiscal year 1975, Western has deferred either an annual O&M and/or interest expense payment in one or more years for 12 of the 15 projects. As of September 30, 1995, 9 of the 15 projects still had about $196 million in outstanding debt related to deferred payments. Western plans to recover the majority of these costs over time. More detailed information about Western's deferred payments over the last 20 years can be found in chapter 3 and appendix IV, and a discussion of FERC's role in rate-setting can be found in appendix VI.

According to Southeastern officials, severe drought conditions in the 1980s created poor water conditions and, as a result, insufficient revenue to cover annual interest and O&M payments. Southeastern had also deferred payments in other years due to poor water conditions. Southwestern deferred interest payments in 1977 and O&M and interest payments in 1981. According to Southwestern officials, the payments were deferred primarily because of poor water conditions. Both Southeastern and Southwestern had repaid all their deferred payments as of the end of fiscal year 1995.

Summary of Unrecovered Power-related Costs

We estimate that, for the five main power-related activities identified in this chapter, the annual unrecovered costs for the three PMAS is about $83 million for fiscal year 1995. In addition, as of September 30, 1995, we estimate that total cumulative unrecovered power costs could be as much as $1.8 billion. Our analysis of unrecovered power-related costs is shown in table 2.2.

[22]Western does not record a liability to recognize deferred payments. Instead, deferred payments are reflected as a reduction in Accumulated Net Revenues on Western's Statements of Assets, Federal Investment, and Liabilities (Balance Sheet). Western's external auditor has determined that this treatment of deferred payments by Western satisfies the DOE regulation that requires a liability to be recognized for deferred payments. For rate-setting purposes, the deferred payments are treated as debt.

Table 2.2: Estimated Total Unrecovered Annual and Cumulative Power-related Costs as of and for the Year Ending September 30, 1995

Dollars in millions

Description	Annual - 1995	Cumulative
Pension and postretirement health benefits	$16.4	$436.0
Russell Project (pumping units)		
Capitalized interest for fiscal year 1995	25.6	
CWIP balance[a]		488.0
Truman Project	0.9	31.0
Washoe Project[b]	•	8.9
Abandoned Transmission Line		
Capital construction costs		14.5
Unrecovered interest	0.4	6.4
Irrigation-related capital costs at Pick-Sloan	13.6[c]	454.0[d]
Deferred payments at Western	0.8	195.7
Irrigation-related O&M at Pick-Sloan	2.1	15.3[e]
Environmental costs	23.6	152.5[e]
Total	**$83.4**	**$1,802.3[f]**

[a]Includes cumulative unrecovered principal and interest costs.

[b]Reflects the cumulative appropriated debt that might not be recovered. Annual deferred payments for O&M and interest expenses are included in “Deferred payments at Western” line item.

[c]This amount represents unrecovered interest and was calculated based on the $454 million.

[d]The $454 million is as of September 30, 1994, because fiscal year 1995 data were not available.

[e]These amounts are converted to constant 1995 dollars to be comparable to the other cumulative dollars that are already reported in fiscal year 1995 dollars.

[f]Amounts for Mead-Phoenix Transmission Line are not included in this estimate because it did not become operational until fiscal year 1996. However, the project’s ability to recover costs in the future is questionable.

Source: GAO estimates based on information provided by the PMAs, operating agencies, and OPM.

Agency Comments and Our Evaluation

In commenting on a draft of this report, the PMAs stated that they agree that there are some power-related costs that were not fully recovered through rates. However, they asserted that the objective of our review was to specifically identify costs that were “unrecoverable,” which they defined as those that have not been and will never be repaid to Treasury under current law and/or policy, as opposed to “unrecovered,” which they defined as those not repaid at a point in time but that will be in the future. While we recognize there is a distinction between the two concepts, we believe that “unrecoverable” costs are essentially a subset of "unrecovered" costs. Moreover, we disagree with the PMAs' assertion about the objective of our review. The objective, based on our agreements with congressional requester staff, was to determine whether all power-related costs incurred through September 30, 1995, had been recovered through electricity rates. Our objective was not to distinguish between "unrecovered" and "unrecoverable" costs. We have clarified the discussion of our objective in the executive summary and other relevant sections of the final report.

In addition, the PMAs disagreed with certain of our characterizations of unrecovered costs in the five main categories discussed in this chapter. These points, and our responses, are discussed below and in appendix II.

Civil Service Pension and Postretirement Health Benefits

The PMAs agreed that the full costs of these benefits are not included in PMA power rates. They suggested that we more fully reflect the content of this chapter in our executive summary by noting therein that the cost underrecovery associated with CSRS pensions should go away over time as CSRS employees retire and the federal workforce is comprised of employees covered by FERS, which is fully funded annually. In response, we added an explanatory statement to the executive summary. However, we also note in our executive summary that the unrecovered costs associated with postretirement health benefits will not be eliminated after the shift from CSRS to FERS.

In addition, the PMAs believe that they cannot deposit power revenues into the Civil Service Retirement and Disability Fund (Fund) to pay for unfunded retirement benefits, because doing so would violate federal appropriations law by augmenting the annual appropriation made to the Fund. Our objective was not to address whether the PMAs should or should not recover these costs; our objective was to determine whether these costs were unrecovered. Consequently, we did not address whether it would be appropriate for the PMAs to deposit power revenues directly into the Fund to pay for these costs. We agree that should the Congress decide that the PMAs should deposit directly into the Fund an amount to cover these costs, the Congress should enact legislation permitting a transfer of that amount into the Fund. Alternatively, the augmentation issue could be avoided by depositing amounts recovered, like many other PMA ratepayer collections, into the General Fund of the Treasury where the revenue would be available to the Congress to appropriate into the Fund to cover the full cost to the government of CSRS pensions. Recovery of postretirement health benefits could be handled the same way.

The PMAS also believe that our reference to OMB Circular A-25 in this chapter was improper, because the PMAS do not recover costs in accordance with the Circular. We agree that the PMAS do not follow Circular A-25, and we note in this chapter that recovery of power-related costs has been implemented through DOE Order RA 6120.2, which does not adopt the guidance in Circular A-25 or otherwise refer to it. We do not state that the PMAS are required to follow Circular A-25; instead, we use the Circular as criteria for defining all the costs associated with producing and marketing federal hydropower. Developing such a definition of full costs was necessary before assessing whether the PMAS were recovering all power-related costs through rates, which was one of the objectives of our review.

Construction Costs for Nonoperational Projects

The PMAS believe that we inappropriately characterized the costs associated with nonoperational projects, specifically Russell and Truman. They assert that we characterized those costs as not only unrecovered but also likely never to be recovered. That assertion is not accurate. Regarding the Russell Project, in our draft report we state that, if the nonoperational pumping units are never allowed to operate commercially, the costs associated with their construction will likely not be recovered. We do not state that it is likely that the units will not be allowed to operate commercially. We only point out the fact that the units have been in CWIP for 20 years and litigation has been ongoing since 1988. We believe these facts demonstrate that the ultimate operation of the Russell pumping units is not a certainty. Moreover, we specifically reiterate Southeastern management's belief that the pumping units will be allowed to operate commercially and that these costs will be recovered in the future. However, in response to the PMAS' concerns, we revised the final report to state that it is unclear whether these costs will be recovered if the project never operates to the capacity designed.

Regarding the Truman Project, we state that, with FERC's concurrence, certain costs associated with nonoperational pumping units have been deferred from power rates. We do not state that it is likely that the costs will never be recovered. We merely demonstrate that the ultimate operation of these pumping units is not a certainty. Moreover, we specifically state Southwestern management's belief that the costs will be recovered if the facilities become operational.

The PMAS state that we should incorporate into the report the similarity of Southeastern's handling of the Russell Project's cost recovery to similar situations for other utilities governed by FERC and state public utility commissions. As discussed in chapter 4, we agree that FERC and state public utility commissions disallow certain costs and that shareholders of IOUs, not ratepayers, bear these costs. However, we do not believe that Southeastern's handling of the Russell Project is similar to that of other utilities. Compared to other utilities, the relative dollar amount and the length of time for the deferral of Russell costs from Southeastern's rates are unique. Note that construction of the Russell Project began in 1976 and the pumping units are still recorded as CWIP today. Thus, Southeastern has not recovered any costs for the nonoperational units. In contrast, IOUs attempt to recover costs immediately, even in situations where the ultimate success of the project is still uncertain.

The PMAS state that an abandoned transmission line for Western's Pacific Northwest-Southwest Intertie Project cannot be declared nonreimbursable or unrecoverable because Western does not have direct legislative authority to do so. As a result, the PMAS assert that Western will include the costs of the abandoned transmission line in rates. This position is contrary to that provided to us during our review. Previously we had not seen any indication that Western planned to include these costs in rates, and all indications were that the costs would be declared nonreimbursable. As stated in this chapter, transmission line construction was discontinued in 1969 and the costs were still included in Western's financial statements at September 30, 1995. The costs associated with the abandoned line have not been recovered, and no interest has been paid to the Treasury. We estimate that at September 30, 1995, the total unrecovered costs for this abandoned transmission line are about $20.9 million.

Projects With Questionable Ability to Recover Costs

The PMAS believe that our description of the economic viability of two projects, Washoe and Mead-Phoenix, needs to be clarified. Specifically, the PMAS state that they are reluctant to conclude that projects that are uneconomic today will remain so forever. We agree that project conditions can change over time and that projects experiencing financial problems today, such as Mead-Phoenix, may not face financial problems forever. In addition, we believe that given the increased competition in the wholesale electricity market and wholesale electricity rates that are expected to fall, some projects that are viable today may not be economic in the future. Regarding Washoe, we concur with Western's assessment in its 1995 annual report that "Based on current conditions it is unlikely the project will be able to generate sufficient revenues to repay the Federal investment." In addition, we correctly state that the project has been unable to recover all of its O&M and interest expenses and had outstanding deferred payments of $3.9 million as of September 30, 1995. Regarding Mead-Phoenix, we state that a Western official does not expect the project, in its first few months of operation, to generate sufficient revenue to recover all O&M and interest expenses. We believe this fact supports our statement that the project has “questionable financial viability.”

Suballocated Pick-Sloan Power Costs

The PMAs generally agreed with this section of the chapter, but suggested that we add two points. First, they suggested that more emphasis be placed on the fact that the methodology for cost allocations cannot be changed without congressional approval. We concur with this suggestion and have revised our report accordingly.

Second, the PMAs suggested that our report include a statement from our May 1996 testimony that noted that the Pick-Sloan Program incorporates agreements reached decades ago and that any changes to power and irrigation purposes may necessitate reviewing other aspects of the agreements. We have incorporated this statement into our executive summary and chapter 2.

Favorable Terms Result in Subsidized Financing

The three PMAS receive favorable terms in repaying the appropriated debt that finances capital projects. In addition, the interest rates on outstanding appropriated debt are lower than the cost to the federal government of providing this financing. As a result, a financing subsidy exists because the interest income earned by Treasury on the appropriated debt is less than Treasury's related interest expense. We estimate that the financing subsidy for the three PMAS for fiscal year 1995 was about $228 million. Cumulatively, this subsidy amounts to several billion dollars. It is important to note that the PMAS were generally following applicable laws and regulations regarding the financing of capital projects.

PMAs' Financing Costs Are Lower Than the Government's Cost of Providing the Financing

The PMAS have accumulated substantial amounts of appropriated debt at low interest rates. This situation has resulted primarily because the PMAS repay high interest rate debt first and because PMA appropriated debt incurred prior to 1983 was generally at below market interest rates.

PMAs Have Substantial Debt

Historically, a large portion of capital construction projects have been financed with appropriated debt. The three PMAS are responsible for repaying the appropriated debt, which amounted to about $5.4 billion as of September 30, 1995. In addition, as of September 30, 1995, Western was responsible for repaying about $1.5 billion of irrigation-related construction costs (which we refer to as irrigation debt), which is discussed later in this chapter. While the total appropriated debt for the three PMAS has risen over the last 5 years, it has not risen for all of the PMAS. As shown in table 3.1, the appropriated debt balances for Southwestern have declined over the last 5 years. Southeastern's appropriated debt has remained relatively constant. In contrast, Western's appropriated debt has increased by $377 million for the same 5-year period. Western's increase is due primarily to capital spending for new or replacement projects and deferred payments for several projects that resulted in very little or no principal on debt being repaid.

Table 3.1: PMAs' Total Appropriated Debt as of September 30, 1991 Through 1995

Dollars in millions

	Appropriated Debt as of September 30,				
PMA	**1991**	**1992**	**1993**	**1994**	**1995**
Southeastern	$1,425	$1,442	$1,443	$1,467	$1,491
Southwestern	769	750	721	712	686
Western[a]	2,807	2,911	3,017	3,145	3,184
Total	**$5,001**	**$5,103**	**$5,181**	**$5,324**	**$5,361**

[a]Excludes Western's irrigation debt; includes deferred payments.

Source: Derived by GAO from PMA audited financial statements and other data provided by the PMAs.

PMAs Have Flexible Repayment Terms

Because the power marketed by PMAS is generated at hydroelectric dams, the amount of power available for them to sell is greatly dependent on weather conditions. During years in which precipitation is high, reservoir levels are sufficient to generate large quantities of electricity. In drought years, however, reservoir levels are reduced and there is less electricity generated and available for sale by the PMAS.

The Flood Control Act of 1944 provides that appropriated debt must be repaid within "a reasonable period of years," but it does not specify that any principal on outstanding debt be repaid in any particular year. The Department of Energy's (DOE) interpretation of this law, Order RA 6120.2, specifies that, unless otherwise prescribed by law, each federal dollar spent on a capital project is to be repaid with interest within 50 years. Shorter repayment periods are used for replacements and transmission facilities. DOE's Order RA 6120.2 also requires that PMAS, to the extent possible, repay the highest interest bearing appropriated debt first.[1]

Appropriated debt carries a fixed interest rate with no ability of Treasury to call[2] the debt. Although PMAS are generally required to pay off highest interest debt first, they cannot refinance the debt. Thus, Treasury bears the risk of increases in interest rates and PMAS, to some degree, bear the risk of decreases in interest rates. Western, for example, has some appropriated debt that is at interest rates above the current Treasury 30-year bond rate. However, because Western cannot refinance this debt and does not have

[1]Appropriated debt due in a given fiscal year must be paid first, regardless of interest rate.

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

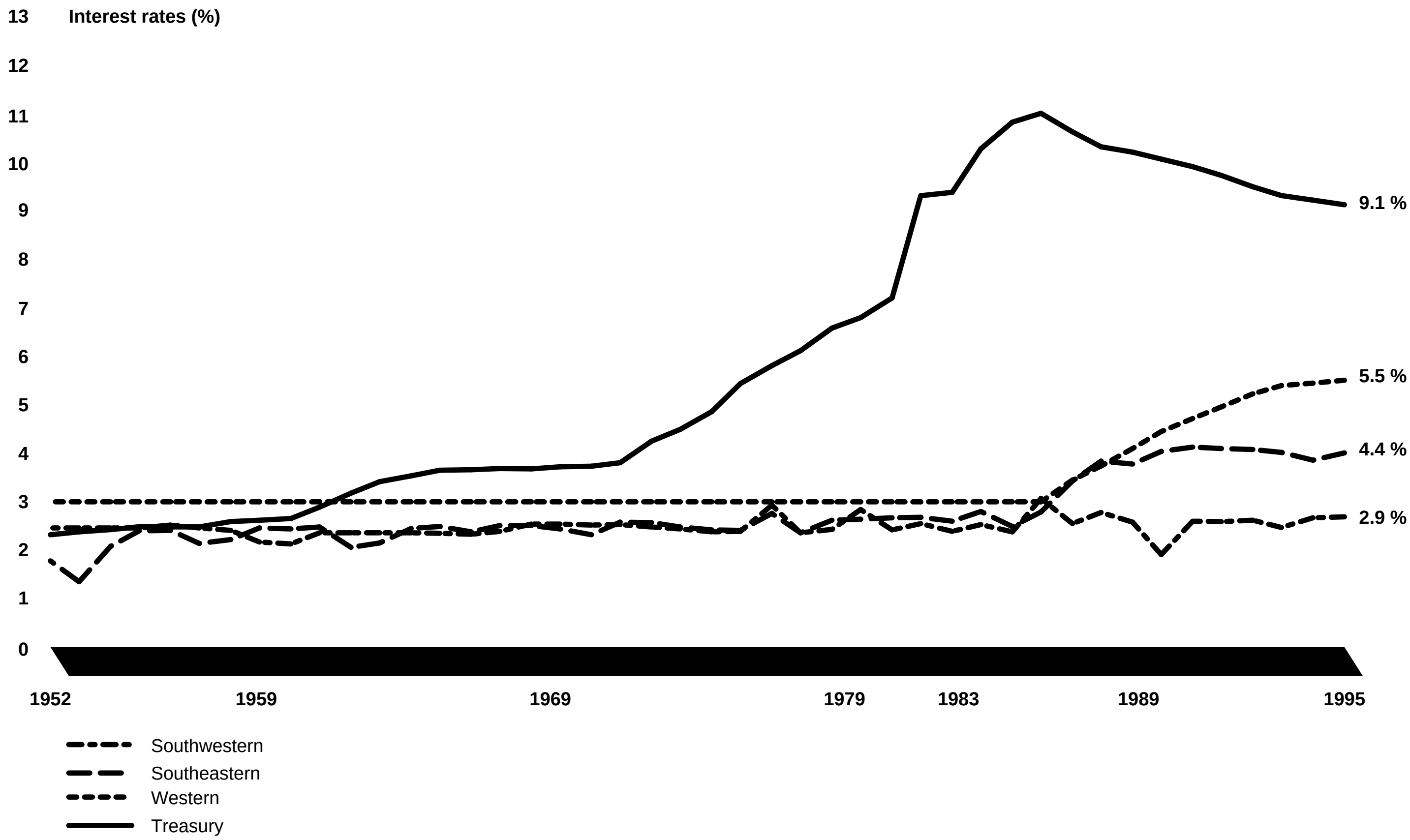
sufficient cash flow to pay it off, it must pay the above-market interest rates.

Interest Rates Before 1983 Were Lower Than Treasury's

From the inception of the PMAS until 1983, the interest rates paid by PMAS on appropriated debt were either established administratively or by specific legislation authorizing and funding the dam construction. The interest rates specified in legislation were generally 2.5 percent to 3.125 percent. Treasury borrowing rates were based on market conditions.

As shown in figure 3.1, when appropriated debt was incurred in the 1950s, the average Treasury interest rate and statutory rates were about the same; however, beginning in the 1960s, the difference between the interest rates paid on the PMAS' outstanding appropriated debt and the average interest rate Treasury paid on its outstanding bond portfolio in the same years started to grow. Because repayment terms on appropriated debt are up to 50 years, this pre-1983 below market interest debt could remain outstanding for several more decades.

Figure 3.1: Average Interest Rates Paid by the PMAs on Appropriated Debt Compared to Rates Paid by Treasury on Outstanding Bond Portfolio—Fiscal Years 1952 to 1995



Note: Western was created in 1977. Interest rates shown before 1977 are for appropriated debt transferred from the Bureau to Western in 1977. Percentages shown at right represent percentages for 1995.

Sources: Data on PMAs developed by GAO from data provided by PMAs; Treasury interest rates: Department of Treasury, summary information related to the public debt of the United States.

By 1985, the average interest rate on Treasury's outstanding bonds had increased to about 11.02 percent, while the average interest rate on the PMAS' outstanding appropriated debt was between 2.8 and 3.1 percent.

Figure 3.1 also shows the large difference between PMAs in average interest rates on outstanding appropriated debt and the impact of the higher interest rates required after 1983. As of September 30, 1995, Southwestern's average interest rate on appropriated debt was 2.9 percent, compared to 4.4 percent for Southeastern and 5.5 percent for Western. Southwestern has had strong water years, and its cash flow has allowed repayment of most new appropriated debt, while the low interest debt remains unpaid. According to Southwestern, part of the reason for the strong cash flow is the inclusion in rates of a provision for future capital replacements, which causes rates to be 10 percent higher than necessary to cover current expenses. As of September 30, 1995, only about $45 million of Southwestern's outstanding appropriated debt of $686 million was financed at interest rates above 3.125 percent.

The weighted-average interest rate paid by Southeastern rose from about 2.7 percent in the early 1980s to about 4.4 percent as of September 30, 1995. The increase in average interest rates reflects Southeastern's inability, due to drought conditions and resulting low revenues, to pay off all the appropriated debt associated with more recent, higher interest rate additions to the power system. In addition, the 6.125 percent interest rate associated with the Russell Project contributed to Southeastern's average interest rate increase. Western's average interest rate has risen due to increased market interest appropriated debt resulting from post-1983 construction projects. In addition, according to Western, drought conditions have been the primary reason O&M and interest expenses have been deferred. As a result, Western's cash flow has not been sufficient to pay off higher interest appropriated debt.

Capital Financing Is Federally Subsidized

The historically low interest rates and flexible repayment terms for PMAs result in a financing subsidy because the interest rates paid by the PMAs do not fully recover the federal government's cost of funds. (See figure 3.1.) To estimate the financing subsidy, we compared Treasury's average interest rate on bonds outstanding, which was about 9.1 percent for fiscal year 1995, to the interest rates on the PMAs' debt as of the end of fiscal year 1995. In this analysis, we used the average interest rate on all Treasury bonds outstanding. The Treasury Bond portfolio includes components with various terms up to 30 years.[3] Since Treasury does not match its borrowing with individual program financing, the average interest rate on

[3]Had we used the average interest rate on bonds with 15 or more years to maturity, which was 8.73 percent as of September 30, 1995, our estimate of the financing subsidy would have been approximately the same. Note that this long-term rate is consistent with the current Treasury rate set out in DOE Order RA 6120.2.

Treasury's entire bond portfolio best reflects its cost of funds. See appendix I for a discussion of our methodology for calculating this financing subsidy.

As shown in table 3.2, the estimated financing subsidy using Treasury's average interest rate on bonds outstanding for fiscal year 1995 was about $228 million.

Table 3.2: Estimated PMA Financing Subsidy, 1995

PMA	Outstanding appropriated debt (dollars in millions)	Weighted average interest rate[a] (percent)	Treasury average interest rate[b] (percent)	Financing subsidy (dollars in millions)
Southeastern	$1,491	4.4	9.1	$70
Southwestern	686	2.9	9.1	43
Western[c]	3,184	5.5	9.1	115
Totals	**$5,361**	**4.9**	**9.1**	**$228**

[a]We calculated the weighted average interest rate for the PMAs by dividing interest costs by average appropriated debt outstanding for 1995.

[b]The 9.1 percent interest rate is the average interest rate paid on Treasury's outstanding bond portfolio at the end of fiscal year 1995.

[c]Excludes Western's irrigation debt; includes deferred payments.

Sources: PMA audited financial statements and other data, and Department of Treasury summary information related to the public debt of the United States.

The above estimate shows that Treasury is currently paying a higher interest rate on its outstanding debt than PMAS are paying on their outstanding appropriated debt. Over the next several decades, as the pre-1983 appropriated debt is repaid, the PMAS' financing subsidy should decrease. However, as shown in figure 3.1, despite new borrowing at market rates, the PMAS' ability to repay high interest debt first has been a factor and likely will continue to contribute to PMA average interest rates being below the effective Treasury average interest rate. In addition, Treasury's inflexible borrowing practices contribute to the magnitude of the financing subsidy. Treasury's general inability to refinance or prepay the federal government's outstanding debt in times of falling or low interest rates is part of the reason for its relatively high 9.1 percent average cost of funds for fiscal year 1995.

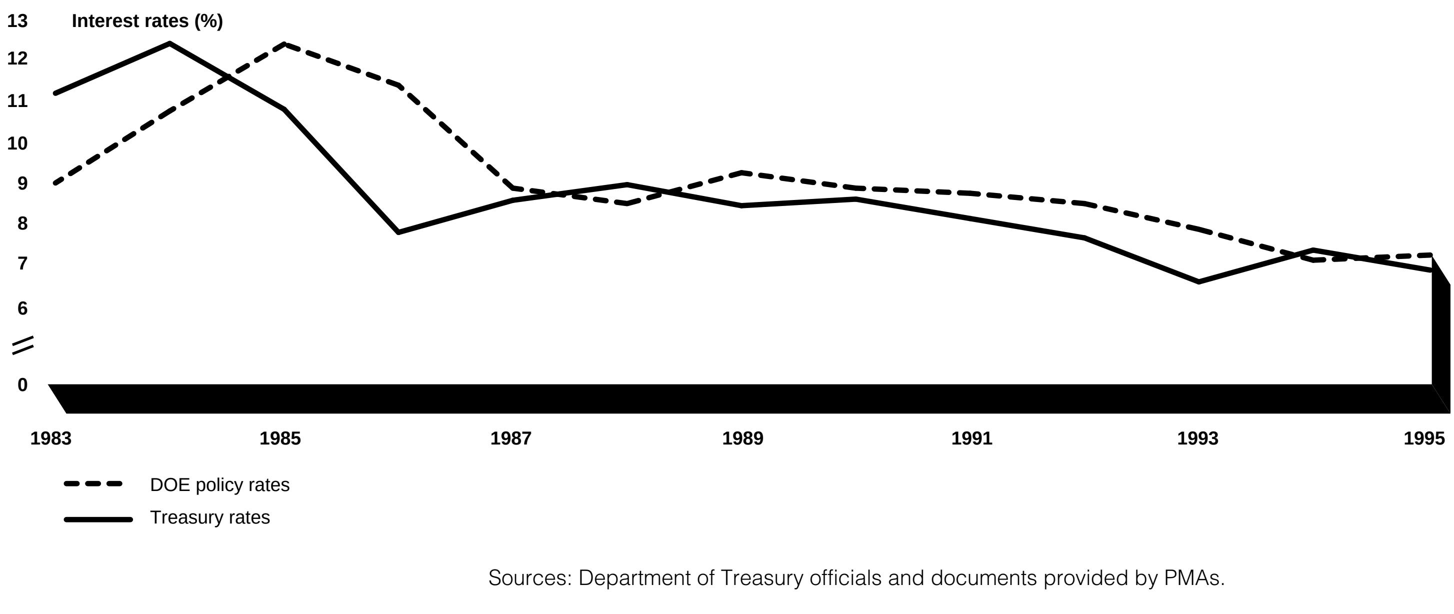
We estimate that, cumulatively, the financing subsidy for the three PMAS is several billion dollars. This estimate is based on the spread between

Treasury and PMA interest rates shown in figure 3.1, which, to varying degrees, has existed for over 30 years.

Interest Rates on New Financing After 1983 Track With Treasury's Rates

In 1983, the Department of Energy increased the interest rates at which new projects or replacements to old projects would be financed by modifying its Order RA 6120.2. This modification required that, in the absence of specific legislation to the contrary, new projects, additions, and equipment replacements made after September 30, 1983, be financed at interest rates equal to the average yield during the preceding fiscal year on interest-bearing marketable securities of the United States, which, at the time the computation is made, have terms of 15 years or more remaining to maturity. As shown in figure 3.2, our review showed that, after 1983, new capital projects or replacements that were debt-financed had interest rates that track closely with Treasury rates.

Figure 3.2: Interest Rates Paid by PMAs on New Financing Compared to Treasury 30-Year Rates for Bonds Issued From 1983 Through 1995



Sources: Department of Treasury officials and documents provided by PMAs.

The new interest rates did not apply to projects that were already under construction. For example, the Russell project, on which construction started in 1975, continued to capitalize interest at the rate applicable in 1975, 6.125 percent. Projects continue to carry the interest rate in effect at the time the projects are started, regardless of when the borrowing occurred. As a result, Treasury's cost of funds could either be greater or less than the project rate depending on whether interest rates are falling or rising. In 1985, the year the first electric generating unit became commercially available at the Russell project, the interest cost borne by Treasury was nearly 10.8 percent, significantly higher than the rate of the interest associated with Russell.

Since the rates the PMAS pay for new appropriated debt are based on the average of Treasury issues in the prior year, during times of falling interest rates, PMAS will usually pay interest on new appropriated debt at rates above current Treasury rates. Conversely, during times of rising interest rates, PMAS will pay interest on new appropriated debt at rates below current Treasury rates.

As shown in figure 3.1, despite new borrowing at market rates, it is the PMAS' ability to repay high interest debt first that has kept and likely will continue to keep their average interest rates below those of Treasury. However, over time, as the pre-1983 appropriated debt is repaid, the PMAS' financing subsidy should eventually decrease.

Western Carries High Levels of Noninterest Bearing Irrigation-Related Debt

In addition to appropriated debt, Western is responsible for repaying certain irrigation-related construction costs on completed irrigation facilities (which we refer to as irrigation debt). As previously noted, reclamation law provides for irrigation assistance to be recovered primarily by power revenues. Although irrigation debt is scheduled to be recovered with power revenues, Western does not view irrigation debt as a PMA cost. Therefore, when Western repays these amounts, neither the costs, nor the related revenues, are reflected in Western's financial statements.[4]

As of September 30, 1995, according to Western, it had approximately $1.5 billion of outstanding irrigation debt,[5] which is to be repaid without

[4]The irrigation debt is not recorded on Western's financial statements. Irrigation debt is discussed in Western's financial statements in the footnote called "Commitments and Contingencies."

[5]See chapter 2 for a discussion of power-related costs that have been allocated to incomplete irrigation facilities.

interest. The repayment period for the irrigation debt could be up to 60 years after completion of construction—up to a 10-year development period plus a 50-year repayment period. Because DOE's repayment policies require PMAS to repay their highest interest rate debt first (unless lower interest-bearing debt is at the end of its repayment period, in which case it would be paid first), the irrigation debt, at zero percent interest, will generally not be repaid until the end of its repayment period. As of September 30, 1995, according to Western, about $32 million of the total $1.5 billion of irrigation debt had been recovered through electricity rates. To the extent irrigation debt is repaid through electricity rates, power users are subsidizing irrigators.

In addition to the long period allowed for repayment of irrigation debt, completed irrigation facilities were under construction for periods ranging from 1 to 27 years, with an average construction period of about 8 years. Therefore, the irrigation debt may not be repaid, on average, until approximately 68 years after the initial costs were incurred. Using the average interest rate on Treasury bonds outstanding for 1995 of 9.1 percent, we estimate that in 1995 the cost to Treasury of Western's $1.5 billion of irrigation debt was $137 million.

This irrigation debt continues to increase at the Pick-Sloan and other projects due to capital improvements allocated to completed irrigation facilities that are to be repaid by Western. To illustrate the future cost to the federal government of new irrigation debt, we calculated the present value of this new debt, assuming it would be repaid at zero percent interest at the end of the average 68 years that the debt would most likely be outstanding. By applying a discount rate of 7 percent, which approximates Treasury's current 30-year bond rate, we estimate that the present value of each dollar that will be repaid 68 years from today is less than one penny.

Agency Comments and Our Evaluation

In commenting on a draft of this report, the PMAS stated that they agree that certain unpaid investments (appropriated debt) are charged an interest expense that is less than the Treasury's cost of borrowing at the time the investment was made. However, the PMAS expressed great concern with our methodology for measuring the magnitude of Treasury's unrecovered financing costs and, as a result, do not concur with our estimate of the magnitude of this cost. The PMAS believe our approach is invalid and is equivalent to assuming that the PMAS refinance their appropriated debt on an annual basis. The PMAS believe that a more accurate methodology for determining the magnitude of the unrecovered financing cost would be to compare each investment's fixed interest rate against Treasury's cost of borrowing in the year the investment was placed in service. Thus, they propose calculating the 1995 financing difference by comparing the Treasury's cost of funds in the year of the PMA investment to the actual PMA interest rate on that investment.

As stated in this chapter, we believe that there is a financing subsidy on the PMAs' appropriated debt because the interest rates the PMAs pay do not fully recover the federal government's cost of funds. We characterize this situation as a financing subsidy because there is a net cost to the federal government of providing the PMAs with appropriated debt. We do not believe the methodology proposed by the PMAs captures the full amount of this subsidy because it does not consider the impact of the PMAs' flexible repayment terms or, as discussed below, the impact of Treasury's borrowing practices. As discussed in appendix I, the methodology described by the PMAs would be a more accurate means to calculate the portion of the subsidy related to the below market financing. However, the records were not available at Western to make the type of specific calculation the PMAs proposed.

We calculated the 1995 estimated financing subsidy by taking the difference between the PMAs' weighted average interest rate for 1995 and the Treasury's average interest rate on its entire bond portfolio. Since Treasury borrows for the needs of the entire federal government using short-term and long-term financing, and does not match specific borrowings with the PMAs' appropriated debt financing, the average interest rate on Treasury's entire bond portfolio best reflects its cost of funds. We believe our approach reasonably captures both the impact of the below market financing provided the PMAs prior to 1983 and the flexible repayment terms currently afforded the PMAs under DOE policies. To help ensure that our methodology was reasonable, we spoke to representatives of OMB, Treasury, and the Congressional Budget Office.

The PMAs disagree with our assertion that the Treasury's additional cost is caused, in part, by the DOE policy of allowing the PMAs to pay off the highest interest rate debt first. The PMAs believe that as long as the interest rate assigned to each PMA borrowing reflects the Treasury's cost of borrowing at the time, then Treasury is kept whole and no additional cost is incurred. We disagree. Treasury is not "kept whole" because Treasury's borrowing practices are inflexible in that it is generally unable to refinance or prepay outstanding debt in times of falling interest rates. This inflexibility is part of the reason for Treasury's relatively high 9.1 percent average cost of funds. Because of the PMAs' flexibility, and the Treasury's inflexibility, there are, and likely always will be, differences in the cost of funds. In summary, we continue to believe that the PMAs' ability to pay off the highest interest rate appropriated debt first, and at any time they desire within the repayment terms of up to 50 years, results in a financing subsidy.

Federal Subsidies and Inherent Advantages of PMAs Result in Low-cost Power

PMAS market low cost wholesale electricity. PMAS' average revenue per kilowatthour (kWh) for wholesale sales[1] has historically been substantially lower than average revenue per kWh for nonfederal utilities. Some of the difference in average revenue per kWh is attributable to the PMAS' unrecovered power-related costs (see chapter 2) and federally subsidized debt financing. (See chapter 3.) Inherent advantages PMAS have compared to other utilities contribute to lower power production costs and lower average revenue per kWh. One such advantage is that PMAS market primarily low-cost hydropower while other utilities generally must rely on more expensive coal and nuclear plants to generate electricity. Another advantage is that PMAS, as federal agencies, do not, for the most part, pay taxes. PMAS are required to recover several nonpower costs, which is a disadvantage compared to other utilities. Competition in the wholesale electricity market could impact the PMAS' position as marketers of low cost electricity.

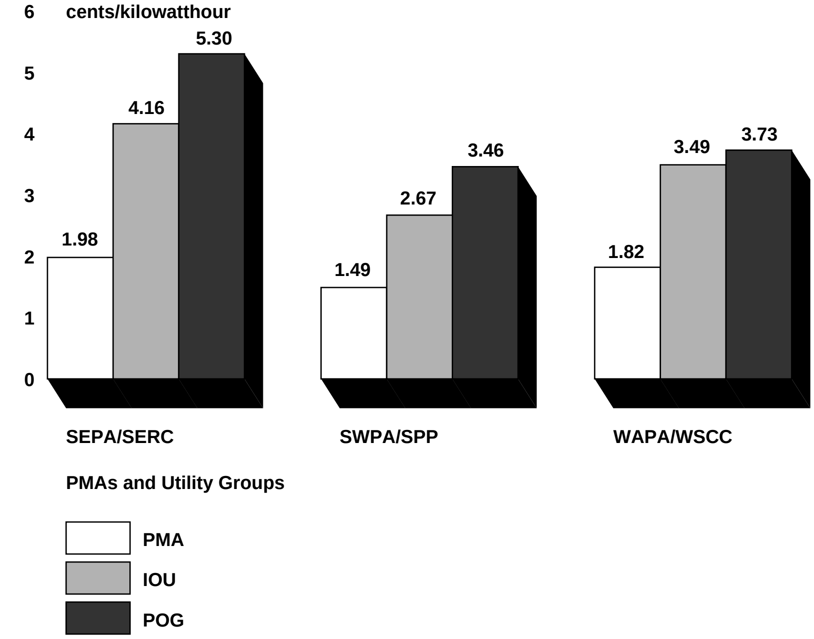
PMAs' Average Revenue Per kWh Has Been Substantially Lower Than Nonfederal Utilities

As shown in figure 4.1, in 1994 the PMAS' average revenue per kWh was more than 40 percent lower than IOUS and publicly owned generating utilities (POGS) in the primary North American Electric Reliability Council[2] (NERC) regions in which the PMAS operate.

[1]The average revenue per kilowatthour for wholesale sales (sales for resale) is referred to in this report as average revenue per kWh. This average is calculated by dividing total revenue from the sale of wholesale electricity by the total wholesale kilowatthours sold. Because PMAs and POGs generally recover costs through rates with no profit, average revenue per kWh should be reflective of PMAs' and POGs' full power production costs. For IOUs, average revenue per kWh should represent cost plus the regulated rate of return. Given that a large portion of IOU rate of return (net income), 80 percent, is used to pay common stock dividends, which is a financing cost, average revenue per kWh also approximates power production cost for IOUs. The Energy Information Administration 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 another for wholesale energy comprises numerous transaction-specific factors including the fee charged for reserving a portion of capacity, the fee for the energy actually delivered, and the fee for the use of the facilities. These fees are influenced by factors such as time of delivery, quantity of energy, and reliability of supply.

[2]The North American Electric Reliability Council 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. NERC consists of nine regional reliability councils and encompasses essentially all the power systems of the contiguous United States, as well as parts of Canada and Mexico.

Figure 4.1: Average Revenue Per kWh of Wholesale Power Sold, 1994



Note: 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' 1994 annual reports, Energy Information Administration (EIA), and American Public Power Association (APPA).

According to the Energy Information Administration, in 1994 the nationwide average revenue per kWh was 3.5 cents for IOUs and 3.9 cents for POGs. The PMAs' average revenue per kWh in 1994, by rate-setting system, ranged from a low of 0.66 cents per kWh for Southwestern's Robert D. Willis system to a high of 3.09 cents per kWh for Southeastern's Georgia-Alabama-South Carolina system. We also reviewed each PMA's average revenue per kWh compared to national averages for IOUs and POGs from 1990 through 1993. During that period, the PMAs' average revenue per kWh was consistently at least 40 percent less than those of IOUs and POGs. A detailed comparison of PMA, POG, and IOU average revenue per kWh for 1990 through 1994 and a comparison of each PMA's average revenue per kWh by rate-setting system to IOUs and POGs in the applicable NERC regions for 1994 is provided in appendix V. We have provided these comparisons by rate-setting system because each PMA system and corresponding NERC region has different average revenue per kWh. These average revenues per kWh may vary considerably by rate-setting system due to customer mix, contractual arrangements, and regional environmental factors such as streamflow[3] and wildlife.

In 1994, Southwestern's average revenue per kWh was the lowest of the three PMAS. The PMAS' average revenue per kWh, which is generally reflective of power production costs, differs for a number of reasons, such as average interest rates, streamflow, and the operating efficiency of the hydroelectric plants. As discussed in chapter 3, Southwestern has significantly lower average interest rates than the other PMAS. In addition, Southwestern had above average streamflow in 1994 and other recent years. Western, in contrast, has had deferred payments in the 1990s primarily due to drought conditions. A potential reason for higher average revenue per kWh for Southeastern is the operating condition of hydroelectric plants that generate the power that it markets. We recently reported that the Corps' hydroelectric plants in the Southeast have experienced lengthy outages resulting in declines in reliability and availability of power.[4] We did not review the hydroelectric plants that generate the power marketed by Southwestern and Western to determine if similar operating problems exist.

According to the American Public Power Association (APPA), POGS' average revenue per kWh were higher than IOUS' average revenue per kWh for several reasons. First, POGS sell a higher percentage of wholesale power under firm power contracts, which command higher prices than nonfirm sales. Second, the timing of many POGS' construction of coal and nuclear generating facilities, in the late 1970s and early 1980s, coincided with new environmental regulations with which previously built facilities were not required to comply. This is in contrast to many IOUS that built coal plants before the 1970s. Also, POGS often do not have enough of their own generating capacity to meet customer needs and thus purchase power from IOUS.

There are some limitations to our comparison of average revenue per kWh. The most recent industry data we could obtain was 1994. Since that time, competition has increased and may have reduced the average revenue per kWh. In addition, we did not include independent power

[3]Streamflow is the quantity of water passing a given point in a stream or river during a given period, usually expressed in cubic feet per second. Streamflow is primarily dependent on regional weather conditions.

[4]See Federal Power: Outages Reduce the Reliability of Hydroelectric Power Plants in the Southeast (GAO/T-RCED-96-180, July 25, 1996).

producers (IPPS) in our comparison because similar information was not readily available. IPPS supply a small percentage of the total market (8 percent) with electricity; however, IPPS are providing a large portion of the new capacity[5] with low cost, natural gas-fired turbines, which is driving wholesale electric rates down. IPPS could pose a significant competitive threat to the PMAS. Despite these limitations, we believe that our comparison of the average revenue per kWh is a strong indicator of the relative power production cost and overall competitive position of the PMAS compared to other utilities.

Several Systems Face Competitive Pressure

Most of the PMAS' 17 different rate-setting systems appear to be in a strong competitive position compared to POGS and IOUS in their areas. However, several systems have high or increasing production costs. Increasing competition in the utility industry may limit their ability to raise rates. One of these systems, the Washoe Project, is not viable under existing operating conditions. Western is selling electricity from this project for 1.9 cents per kWh that is costing 11 cents per kWh to produce. Other projects, such as Pick-Sloan, face mounting pressure to continue to increase rates. Pick-Sloan had outstanding deferred payments of $131 million as of September 30, 1995. To recover deferred payments and potentially recover irrigation debt, Pick-Sloan faces upward rate pressure. Competition could make it difficult for this project to recover its substantial irrigation debt. Although low cost now, potential rate increases at Pick-Sloan could affect its future competitive position.

Another project, the Central Valley Project (CVP), has started to feel the effects of competition and has acted to improve its position. Much of the CVP power that Western sells is purchased from nonfederal sources at prices established in long-term contracts. CVP "passes through" the costs of purchasing this power to its customers; no profit is made. In fiscal year 1995, CVP purchased less power for its customers than in fiscal year 1994 for a variety of reasons. According to CVP officials, one of the reasons for this was that its customers were able to obtain needed power from other sources at a lower price than the price CVP had established in its contracts. CVP officials told us that they expect this trend to continue and have begun to terminate the contracts they hold to purchase power—a process which they expect to continue over the next several years.

The rates that CVP charges for firm power are composite; that is, they incorporate the cost of both CVP-purchased and CVP-generated power. CVP's

[5]Capacity is the amount of electric power that can be delivered by a generating unit at one time.

average revenue per kWh is the highest when compared to other projects where Western markets power. One reason for this is the inclusion in rates of the relatively expensive CVP-purchased power. Since CVP's repayment study projects the purchase of less and less power in coming years, the consequence could be lower rates.

Except for the Georgia-Alabama-South Carolina system, it appears that Southeastern's rate-setting systems are in a relatively strong competitive position. As discussed in chapter 2, if the inactive portion of the Russell Project is brought on line, according to Southeastern officials, it would likely cause an increase in rates for the Georgia-Alabama-South Carolina system because of the $488 million invested in this portion of the project. As shown in appendix V, the average revenue per kWh at this system—3.09 cents per kWh—is the highest for all three PMAS.

Southwestern is in a very strong competitive position in all of its rate-setting systems. As shown in appendix V, there are substantial differences in the average revenue per kWh of Southwestern's rate-setting systems and the average revenue per kWh of the IOUS and POGS in the NERC regions in which Southwestern markets power.

As discussed earlier, the impact of competition in the wholesale electricity market, and the increasing impact of low cost IPP electricity, could affect the PMAS' competitive position.

Federal Subsidies and Inherent Advantages Contribute to Low-cost Power

PMAS sell primarily wholesale power generated at federal water projects. The Flood Control Act of 1944 calls for the PMAS to encourage the most widespread use of electricity at the lowest possible rates to consumers. The PMAS do not sell power for profit. IOUS generally provide a defined service area with power and build new generating capacity to meet future customer needs. Both wholesale and retail electricity is sold by IOUS. The objective of IOUS is to produce a return for their shareholders. POGS are similar to PMAS in that they are owned and/or operated by governmental entities—federal, state, or local. They are nonprofit entities established to serve their communities and nearby consumers at cost. POGS sell both wholesale and retail electricity.

Key operating and financial differences exist between PMAS and other utilities. Many of these differences, including the PMAS' reliance on hydropower, other utilities' need to pay various taxes, accounting and rate-setting practices, and financing, result in advantages to the PMAS and contribute to the substantial difference in power production costs. In this section, we compare key operating and financial factors of PMAS to IOUS and POGS. We selected two IOUS and two POGS from each of the PMAS' service areas. In order to be selected, each utility had to generate at least some hydroelectricity. We contacted APPA and the Edison Electric Institute (EEI) to corroborate our findings from the individual utilities. For a description of the methodology for our comparison, see appendix I.

Generation of Electricity

PMAS rely almost entirely on hydroelectric power while other utilities are primarily dependent on coal and nuclear generating plants. Table 4.1 shows the large contrast in percent of power coming from various generating sources used by the PMAS and other utilities.

Table 4.1: Net Generation, PMAs and Other Utilities, 1995

Figures in percent

	Coal	Nuclear	Gas	Hydro	Other
PMAs	8	0	0	92	0
Other utilities	55	25	12	6	2

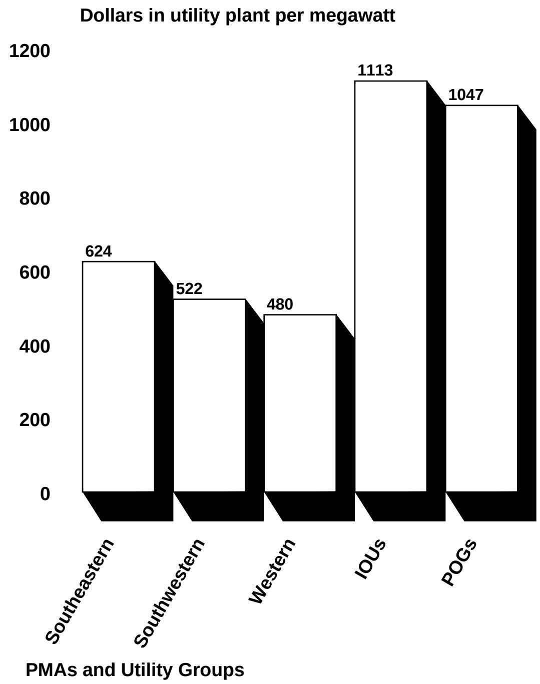
Source: Energy Information Administration.

According to APPA, POGS on average generated 26 percent[6] of their electricity from hydroelectric plants in 1994. EEI reported that IOUS generated an average of 4 percent of electricity from hydroelectric plants between 1990 and 1994. The hydroelectric plants that generate the power marketed by the PMAS have several key cost advantages over coal and nuclear plants that contribute to lower power production costs, including relatively low capital construction costs and no fuel costs.

To show the relatively low capital cost of these hydroelectric plants, we compared the investment in utility plant per megawatt of capacity for these plants to those of other utilities. As shown in figure 4.2, Southeastern, Southwestern, and Western have substantially less invested in power plants than other utilities, which contributes to their lower power production costs. Note that Southeastern's investment in utility plant per megawatt is substantially higher than the other PMAS. This is because the Russell project, which is discussed in chapter 2, has incurred construction costs of $488 million with no corresponding generating capacity.

[6]This average does not include any adjustments for joint ownership of plants. Credit for all generation from a plant is given to the operator of the plant.

Figure 4.2: Investment in Utility Plant per Megawatt of Generating Capacity



Source: GAO analysis of financial data in PMAs' 1994 annual reports and EIA data.

Compared to other utilities, the lower investment in PMA-related hydroelectric plants is partly the result of construction of these plants 30 to 60 years ago, at lower costs compared to more recent construction. Unlike the PMAS and operating agencies, IOUS build new capacity to meet the future needs of customers. The higher construction costs for the other utilities shown in figure 4.2 reflects more recent construction of coal and nuclear plants. Many IOU and POG nuclear plants that were completed and are operating had significant capital construction costs, which is at least partly due to stringent Nuclear Regulatory Commission (NRC) 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. Our analysis excluded nuclear plants that are mothballed[7]

[7]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.

and thus provide no capacity while resulting in significant capital costs. Inclusion of these "regulatory assets" would have increased the POG and IOU investment. Appendix I describes the methodology used for computing the ratios in figure 4.2.

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 1994, POGS' fuel costs represented 15 percent of operating revenues, while IOUS' fuel costs represented 17 percent of operating revenue. The PMAS, on the other hand, have the benefit of marketing power from hydroelectric plants, which do not have an associated fuel cost.[8]

The PMAS do have certain costs of operations resulting from hydroelectric production that differ from coal and nuclear generation. According to Southwestern, the Corps is subject to federal regulations, such as the Endangered Species Act and the National Environmental Policy Act. Southwestern, through the Corps' operations, estimates that it lost about $1.3 million in revenues over the past 5 years through water spilled[9] and operations changed to improve water quality for downstream recreational fisheries. Southwestern also estimates that it has spent nearly $500,000 on equipment, studies, and services in an effort to find solutions to the water quality/sport fisheries problem. Southeastern and Western face similar issues related to the Corps and Bureau operations of their respective hydroelectric facilities. It is important to note here that capital and O&M costs relating to nonpower uses of federal dams, including flood control, navigation, and recreation, are allocated to those other purposes and not included in PMA electricity rates. As discussed in chapter 1, on average, the cost allocations to power are 69 percent, 35 percent, and 50 percent for projects related to Southeastern, Southwestern, and Western, respectively.

POGS and IOUS face similar regulations in running hydroelectric dams. The utilities we contacted reported to us that they need to comply with numerous laws including the Federal Power Act, Federal Water Pollution Control Act, Clean Water Act, and the Endangered Species Act. In

[8]As noted in table 4.1, a relatively small amount of electricity marketed by Western is produced from coal.

[9]A water spill occurs when an operating agency allows water to pass through the dam without producing electricity. Water may be spilled because a reservoir is too full or because extra water is needed for navigation, recreation, or irrigation flows. Water may be spilled to maintain water quality. Water temperature and dissolved oxygen levels may be controlled through water spillage.

addition, these utilities are subject to regulations of government agencies such as FERC, the Forest Service, and other state and local governmental agencies. The operations of hydropower projects at the utilities we contacted are greatly affected by these laws and regulations. In fact, several utilities reported to us that the laws and regulations make certain new hydroelectric projects economically infeasible. As with Southwestern, one of the POGs reported that it is required to spill water, which results in over $1 million per year in lost revenues. Some of the utilities reported that they recover a portion of O&M costs for recreational services and facilities; however, for the most part, the capital and O&M costs incurred in complying with laws and regulations are recovered through electricity rate charges.

Income and Other Taxes

PMAs, as federal entities, are generally not subject to taxes, which gives them a substantial power production cost advantage over POGs and IOUs. POGs, as publicly owned utilities, typically do not pay income taxes because they are a unit of state or local government. However, many POGs do make payments in lieu of taxes to local governments. IOUs are subject to several forms of taxation. Such taxes include all the general taxation rules in the federal tax laws as well as a variety of state and local taxes, such as income tax, gross receipts tax, franchise tax, and property tax.

With the exception of the Boulder Canyon Project, the PMAs generally do not make payments in lieu of taxes to state or local governments. The Boulder Canyon Project Adjustment Act of 1940 requires annual payments to the states of Arizona and Nevada. In 1995, the project paid $600,000, or 1.2 percent of operating revenues to these states.

According to EEI, in 1994, IOUs, on average, paid taxes totaling about 14 percent of operating revenue. This average varies significantly by state and utility due to differing state and local government taxation laws and various levels of IOU profitability. The IOUs we contacted pay taxes ranging from 11 percent to 20 percent of operating revenue. Examples of taxes paid by the IOUs we contacted are federal and state income tax, real and personal property tax, corporate franchise tax, invested capital tax, and municipal license tax.

POGs are exempt from paying federal or state income taxes. However, most POGs we contacted make a contribution to one or more local governmental entities, generally in lieu of property taxes. APPA conducted a survey[10] and found that 77 percent of the respondents made contributions to local governmental entities; 74 percent of those contributions were payments in lieu of taxes. POGs also contribute free or reduced cost electrical service, the use of employees, and other services such as the use of vehicles, equipment, and materials to local governments. A study[11] of 670 public distribution utilities showed that the median net payments and contributions as a percent of electric operating revenue were 5.8 percent. The range of net payments as a percentage of operating revenue for the POGs we contacted varied from 0 to 17 percent.

Accounting and Rate-Setting Practices

PMAS are agencies of the Department of Energy and thus are required to follow standards recommended by the Federal Accounting Standards Advisory Board (FASAB) and approved by GAO, OMB, and Treasury. Certain FASAB standards directly address accounting requirements for the PMAS. For example, as discussed in chapter 2, SFFAS no. 5 prescribes accounting principles the PMAS will be required to follow for recording the full cost of pension and postretirement health benefits. Because FASAB standards and other relevant federal guidelines do not specifically address regulated entities, the PMAS are allowed to follow the provisions of Statement of Financial Accounting Standards no. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71).[12] The provisions of SFAS no. 71 require, among other things, that the financial statements of a utility reflect the economic effects of rate regulation and provide for a relevant matching of revenues and expenses. Regulatory actions can provide reasonable assurance of the existence of an asset, reduce or eliminate the value of an asset, or impose a liability on the regulated enterprise. For example, if a regulator determined that the costs of a nonproducing power plant were allowable, then the costs of the plant would be carried as a "regulatory asset" and reflected in rates. In contrast, if the costs were determined to be unallowable, the asset would be written off with no corresponding rate charge.

[10]1994 Survey of Local Publicly-Owned Electric Utilities Tax Payments and Contributions to State and Local Government, American Public Power Association.

[11]1994 Payments and Contributions by Public Power Distribution Systems to State and Local Government, American Public Power Association, March 1996.

[12]Private sector entities and the PMAs, where applicable, follow the generally accepted accounting principles of the Financial Accounting Standards Board (FASB).

IOUs are subject to the pronouncements of FASB and thus prepare financial statements in accordance with SFAS 71.[13] POGs are subject to the pronouncements of the Governmental Accounting Standards Board (GASB). GASB Statement 20, Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting, states that if GASB has not addressed an issue, then an entity may follow FASB guidance. POGs generally prepare financial statements in accordance with SFAS 71 since GASB has not addressed regulatory accounting for governmental entities.

IOUs typically use the accrual basis[14] (as modified by SFAS 71) to determine costs to be recovered through electricity rates, using depreciation to recover capital costs. Depreciation as a basis for recovery of capital costs provides a consistent, systematic method on which to base rates by recognizing the cost of the asset equally over its useful life. PMAs and POGs generally use a cash basis or debt service method of setting rates. Under this method, capital costs are recovered through rates as payments for the asset are made. For example, if a capital asset is debt financed, the cost would be included in rates when principal on the debt is repaid or scheduled to be repaid. Repayment terms between PMAs and POGs differ. POGs generally repay principal on debt in fixed annual or semiannual installments, whereas most PMA debt has flexible repayment terms and as such is not required to be repaid until the final year.

Rate recovery terms for the various types of utilities vary. Depreciable lives of hydroelectric assets for the IOUs we contacted range from 22 years to 96 years, with most asset types exceeding 40 years. POGs' tax-exempt bonds are generally repaid over 18 to 40 years. PMAs have 50 years to repay federal appropriations for hydro assets. Therefore, even though the PMAs have flexible repayment terms, in some cases, their costs may ultimately be recovered sooner than the IOUs overall.

[13]Utilities are also subject to the provisions of Statement of Financial Accounting Standards no. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71. Deregulation, a change in the method of regulation, or a change in the competitive environment for an entity's regulated services or products, can cause SFAS no. 101 to be applied. If any of these events occur, the entity would be required to write off related regulatory assets and liabilities. In addition, the entity would be required to determine any impairment to other assets, including plant, and write down the assets, if impaired, to their face value. Given the increasing competition in the electricity market, certain enterprises may cease to meet the criteria for application of SFAS no. 71.

[14]Pronouncements of FASB generally require accrual accounting, which recognizes revenues in the period when earned and expenses in the period when incurred, regardless of when payments are received or made.

The financial statements of the PMAs and POGs are presented on an accrual basis in accordance with SFAS 71. The financial reporting difference created by setting rates on a cash basis and reporting on the accrual basis is recognized in the Federal Investment (Equity) section of the PMA financial statements as accumulated net revenues.[15] POGs generally eliminate a mismatch of income between cash basis rate-setting and accrual basis financial statements by recording an asset (liability) on the balance sheet with an offsetting credit (debit) to the income statement.

There are differences among IOUs, POGs, and PMAs regarding the types of expenses included in power production costs and resultant rates. The types of expenses included in wholesale and retail rates are subject to approval by utility commissions and may be determined by legislation as well as accounting practices. We found that IOUs typically include all expenses in retail rates unless disallowed by a utility commission. If the utility commission deems that certain expenses do not benefit ratepayers, they will prohibit such expenses from being included in retail rates. For example, one state utility commission decided that advertising expenses, membership dues, lobbying fees, and nonutility operation expenses do not benefit ratepayers and therefore were not allowed to be recovered through retail rates. However, these costs are often recovered fully through wholesale rates because FERC generally allows such costs. An example of costs that FERC may disallow from wholesale rates is a portion of CWIP if FERC determines that the IOU has requested an unreasonable amount to be included in rates. Most POGs we contacted include all of their expenses in rates. PMAs' rates, on the other hand, do not include some costs, as discussed in chapter 2. However, PMAs are required to recover certain nonpower costs. For example, Western is required to recover the Hoover Dam Visitor Center costs, which are estimated at about $124 million. In addition, Western is required to repay about $1.5 billion of capital costs related to assistance on completed irrigation facilities (irrigation debt).

According to FERC, often an IOU will determine within the first 3 years of construction that a project is not viable and halt construction so as to minimize expenses which will not provide benefit to ratepayers. Normally if an IOU halts construction on a project, it will pass these costs through to the ratepayers. A customer may challenge the inclusion of such costs in

[15]Accumulated net revenues represent differences between the timing of recognition of expenses and the related revenues, with the primary cause related to the difference between the recognition of capital costs based on depreciation expense for financial reporting purposes and the actual flow of cash for rate-setting purposes. Because revenue from rate-setting on a cash basis has exceeded depreciation for financial reporting purposes, the PMAs' accumulated net revenue balance represents deferred revenue.

rates with the appropriate utility commission. The commission may then conduct a prudency test which serves as the basis for allowing such costs in rates. The purpose of the prudency test is to determine whether it was prudent to build the project at the time construction began. If so, then the cost of the abandoned project would be fully included in the rate base. Even if the project does not meet the prudency test, according to FERC, the ratepayers would still be responsible for some portion of the costs and shareholders would be responsible for the remainder of the costs. PMAS are not subject to FERC's prudency test.

PMAS, because of DOE Order RA 6120.2, do not include project costs in rates until put into commercial service. The Russell Project, although not yet operational but determined viable according to Southeastern, was in construction for 16 years and has been awaiting commercial operation for the last 4 years. As such, costs related to the Russell Project totaling $488 million, including accumulated interest, are still in CWIP and excluded from rates. Compared to other utilities, the relative magnitude and length of time for Southeastern's deferral of Russell from its rates is unique.

IOUS' and POGS' basic rate-setting methods also differ from PMAS. IOUS and POGS generally use a revenue requirements study. For IOUS, the revenue requirement is the amount of money the utility requires to cover its annual expenses while earning a reasonable rate of return for its investors. POGS follow similar methods but do not require a rate of return since they are publicly owned, although some may include an allowance to provide equity capital for the system. Power repayment studies are prepared annually by the PMAS to determine the adequacy of current rates and determine new rates. The power repayment study tests the adequacy of rates; it entails a 5-year cost evaluation period and recovery of costs within their legally permitted repayment periods. The study also forecasts power-related capital and O&M costs that the PMA will be required to repay in the future and projects future revenues based on current rates. If the study shows that revenues generated under current rates will be inadequate to cover expenses, new rates may be designed. Most of the unrecovered costs identified in chapter 2 are not included in the study and, therefore, are not included in the determination of rates.

Financing of Capital Projects

The methods and costs of capital financing vary greatly among the PMAS, POGS, and IOUS. Federal power-related capital projects rely primarily on debt financing from Treasury. This financing is dependent on the appropriations process, discussed in chapter 1. POGS rely primarily on debt financing from the capital market for capital projects. In addition to debt financing, IOUs are able to use equity financing.

PMAs have substantial balances of appropriated debt that have been used to finance the construction of hydroelectric and transmission facilities. As discussed in chapter 3, because of several factors, PMA interest rates on appropriated debt have been subsidized by the federal government. POGs and IOUs also issue debt to finance capital projects. POGs and IOUs typically go to the financial markets to issue various short-term and long-term debt instruments. POGs generally issue bonds that are exempt from federal and state income taxes. This results in POGs getting favorable interest rates on their debt. IOUs issue long-term debt and some short-term instruments, such as commercial paper. IOU interest rates are based on market forces and typically vary based on the bond ratings of the particular IOU. Unlike PMAs, IOUs and POGs have the flexibility to refinance debt in times of falling interest rates. However, as discussed previously, PMAs have the ability to repay higher interest rate debt first, thereby allowing them to effectively manage their debt costs.

According to EIA, the average interest rate for 1994 for all POGs was 5.6 percent. For IOUs, it was 7.3 percent. The average interest rates of the POGs and IOUs we contacted for 1995 were in the same range as for the entire industry in 1994. For the POGs, the low was 5.1 percent and the high was 6.1 percent. The IOUs' range was 6.5 percent to 7.9 percent. In 1995, the PMAs' average interest rates ranged from 2.9 percent for Southwestern to 5.5 percent for Western.

The Bureau has obtained financing for several capital projects from Western's customers, which we will refer to as "third-party financing." The Bureau has the authority to accept contributions from Western's customers to defray the costs of capital construction. As of September 30, 1995, outstanding third-party financing, or customer advances, amounted to about $154 million for the Hoover Dam capital improvement (uprating) program (Boulder Canyon Power System) and about $25 million for the Buffalo Bill project (Pick-Sloan Missouri Basin Power System). The interest rates for the Hoover Dam uprating program range from 5.5 percent to 8.2 percent, and the interest rate for the Buffalo Bill project is 11.07 percent.

Under third-party financing arrangements, Western customers provide funding (primarily from the issuance of bonds) to the Bureau to use for the capital project. The customers pay the debt service cost, and Western records the proceeds as a liability and records interest expense. Western then bills the customers for the production costs of electricity, including the debt service on the third-party financing, and credits the customers for the debt service costs. Essentially, this arrangement results in customers directly paying for capital improvements rather than paying for them indirectly through rates. Unlike the Russell Project, which was financed with appropriated debt, third-party financing shifts many of the risks of construction projects to the customers, who are responsible for the bonds, rather than the federal government.

In addition to debt financing, federal power-related capital projects are financed using a method similar to revenue financing. Revenue financing is paying for capital projects with net cash generated from operations. Revenue financing for the PMAS occurs when power revenues exceed O&M expenses and the resulting net revenue is used to pay off appropriated debt on new projects or replacements in the first year of the repayment period. In effect, the capital appropriation is repaid in the year that it was made with revenue from current power customers. Southwestern, for example, has been able to keep its average interest rate at 2.9 percent by revenue financing its new projects that would have been financed at DOE policy rates. POGS and IOUS also use revenue financing for capital projects. To the extent a utility is able to finance capital projects from net cash flow rather than debt it will reduce future interest expense. In addition to revenue and debt financing, IOUS have access to equity financing. IOUS are able to issue common and preferred stock and typically pay a large portion of earnings out in common dividends. In 1994 the IOU payout ratio[16] was 80 percent. Dividends represent a financing cost for IOUS.

As discussed in chapter 1, PMAS' appropriated debt generally has terms of 50 years for generating projects and 35 to 45 years for transmission investments. Most of the PMA debt follows a "balloon payment methodology," in which principal is due at the end of the repayment period with no required annual amortization. This differs from the IOUS we contacted, who reported maximum maturities on debt of 30 to 40 years. IOUS reported that they generally pay principal off in balloon payments at maturity, either through cash flow from operations or refinancing. POGS reported maximum maturities of 18 to 40 years; however, the POGS generally repay principal in fixed amounts each year. As discussed in the rate-setting section, inclusion of capital costs in rates for PMAS and other utilities varies from the cash (debt service) to the accrual basis.

[16]The payout ratio is calculated by dividing common stock dividends by net income and thus represents the percentage of net income that was paid out in common stock dividends.

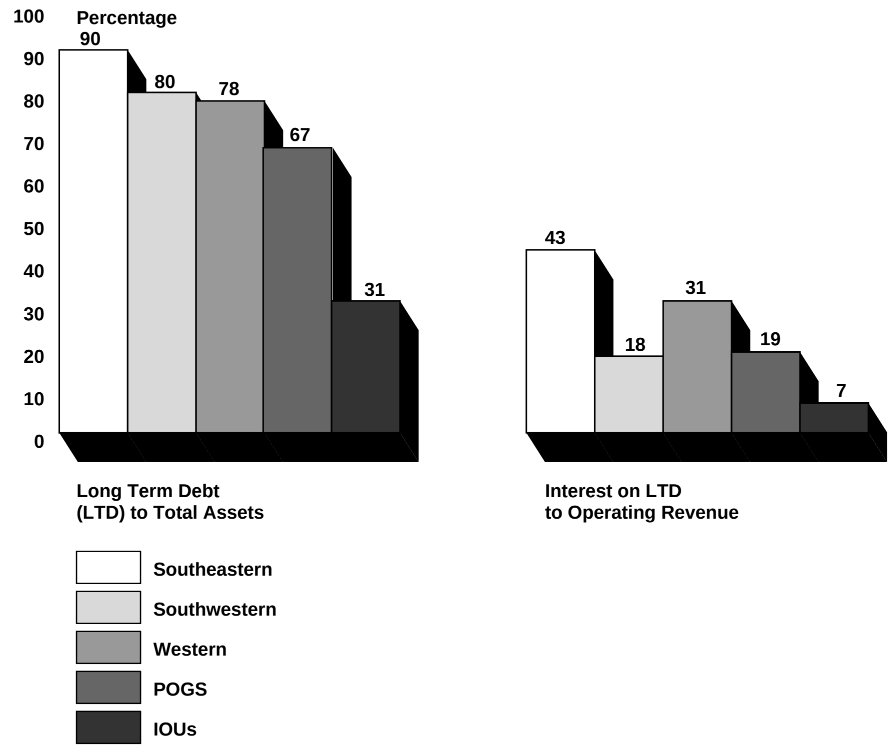
We noted several other differences in financing, including control of capital expenditures and placement costs. The PMAs and operating agencies face the constraints of federal budget pressures in obtaining capital financing. According to the Corps, the focus on the federal deficit has put pressure on PMA and operating agency budgets and has resulted in less funding for PMAs and operating agencies for hydropower capital programs. POGs and IOUs have more direct control over capital budgets. However, POGs and IOUs are thus subject to the scrutiny of the market, such as the bond rating system, which affects the appeal of the bonds to the investing public. IOU financing is also subject to the scrutiny of regulators.

The PMAs, as federal agencies who are appropriated capital funds, do not pay any placement costs[17] or transaction fees. In contrast, POGs and IOUs must pay placement costs. The POGs and IOUs we contacted reported placement costs from .09 percent of the face value of the debt offering up to 1.5 percent. In addition, IOUs reported placement costs on common and preferred equity offerings of about 3 percent.

When compared to IOUs, PMAs and POGs are generally more highly leveraged. Figure 4.3 shows that the PMAs and POGs rely heavily on debt financing for capital projects.

[17]Placement costs include brokers fees, attorney fees, accounting fees, and other costs of public debt or equity offerings.

Figure 4.3: PMAs' Leverage Compared to Other Utilities



Source: GAO analysis of financial data in PMAs' 1994 audited financial statements and EIA data.

The PMAS' and POGS' ratios of long-term debt as a percentage of total assets are much higher than IOUS because PMAS and POGS finance most of their capital expenditures with debt rather than equity or revenue. IOUS may utilize a combination of debt, equity, and revenue financing which results in lower leverage. However, IOUS' also pay dividends to stockholders which are, in essence, a financing cost. This cost is not a factor in the calculation of interest on long-term debt to operating revenue in figure 4.3. If IOUS' common dividends were included in this calculation, then an average of 15 percent of IOUS' operating revenue would be paid for financing costs. There is an expected correlation between long-term debt to total assets and interest on long-term debt to operating revenue for each of the entities. Those utilities that utilize debt to a greater extent to finance capital expenditures have greater interest expense relative to operating revenue.

The PMA ratio of interest on long-term debt to operating revenue would be much higher if interest rates were not subsidized by the federal government, as discussed in chapter 3. The ratio shown for Southeastern is higher than the other PMAs because of the Russell Project, which is incurring capitalized interest but generating no revenue. Southwestern's ratio is only 18 percent because of its low average interest rate of 2.9 percent.

Agency Comments and Our Evaluation

In commenting on a draft of this report, the PMAs stated that they are not truly comparable to other utilities because they have unique characteristics that make certain comparisons against other utilities of limited value. The PMAs stated, for example, that unlike "traditional utilities," they do not have a responsibility to meet load growth in their regions or the authority to acquire new firm power resources. The PMAs stated that it is inappropriate to compare their hydropower costs to coal and nuclear generation of other utilities.

We agree with the PMAs that they are different from other utilities in the ways discussed in this chapter, including cost of production, types of generating facilities, payment of taxes, accounting and rate-setting, and financing. We also discuss in this chapter the different missions and responsibilities of PMAs, IOUs, and POGs. We believe that power customers are primarily concerned with production costs and resultant electricity rates, not whether the supplier is an IOU, POG, or PMA or whether the supplier is using coal, nuclear, or hydroelectric generation. Given increasing competition and electricity rates that are expected to fall, if the PMAs do not remain low-cost suppliers, then they may not be able to recover all power-related costs. Therefore, our discussion of the differences in power production costs between PMAs, IOUs, and POGs and the reasons for these differences is essential.

The PMAs agreed with our statement in this chapter that PMAs are low-cost suppliers of electricity. However, the PMAs are concerned that our use of average revenue per kilowatthour (kWh) is overly simplistic and may mislead readers about the magnitude and causes of differences in costs between PMAs and other utilities. The PMAs do not believe average revenue per kWh takes into account differences in types of electricity sold that result in different prices. They believe a more accurate measure would be to compare similar products being offered by different utilities.

The PMAs appear to be concurring with the results of our analysis but disagreeing with the methodology that led to those results. We continue to believe that the average revenue per kWh is a strong indicator of the relative power production costs of the PMAs as compared to IOUs and POGs. For PMAs and POGs, over time, average revenue per kWh should equal cost because each operates as a nonprofit organization that recovers costs through revenues. For IOUs, average revenue per kWh should represent cost plus the regulated rate of return. Given that a large portion of IOU rate of return (net income), 80 percent, is used to pay common stock dividends, which is a financing cost, average revenue per kWh also approximates power production costs for IOUs.

We acknowledge in appendix I that we did not perform a detailed electricity rate comparison of PMAs to nonfederal utilities. We also state in this chapter that the price that any one utility charges another for wholesale energy comprises numerous factors. We believe that the PMAs' alternative methodology of comparing similar products being offered would provide a reasonable rate or price comparison. However, as the PMAs note in their comments, this analysis would be difficult, and the PMAs themselves have not done it. Also, the PMAs' proposed analysis would not necessarily result in a better indicator of relative production costs because different types of power may be sold above or below total production cost. Average revenue per kWh, on the other hand, better captures total production costs.

The PMAs also stated that a related problem with using average revenue per kWh as a measure of the PMAs' competitiveness is the variability in output of PMA hydropower projects. The PMAs believe our use of average revenue per kWh to indicate competitiveness could result in wide variations in a PMA's competitive position from year to year. In order to address this factor, we reviewed the PMAs' average revenue per kWh for 1990 through 1994. For each of these years, the PMAs' average revenue per kWh was consistently at least 40 percent less than those of IOUs and POGs. We believe that this 5-year comparison is a strong indicator of the PMAs' current competitiveness.

The PMAs also expressed concern that the report gives greater focus to advantages enjoyed by the PMAs without giving equal attention to other costs that the PMAs' customers must repay that would not normally be charged to nonfederal utility customers. The PMAs stated that we report that irrigation assistance is a large subsidy paid by Western's customers and suggested that we also note other examples, such as future replacement costs, the Hoover Dam Visitor Center, payments in lieu of taxes, and billions of irrigation investments that are not even in service.

We believe that our report provides an appropriate discussion of the relative advantages and disadvantages the PMAs have compared to nonfederal utilities. However, we believe the advantages outweigh the disadvantages. The PMAs' use of hydropower plants built 30 to 60 years ago, tax-exempt status, unrecovered costs discussed in chapter 2, and the financing subsidy discussed in chapter 3, in aggregate, provide the PMAs with a substantial cost advantage compared to nonfederal utilities. We believe this large difference is reflected in the average revenue per kWh comparisons shown in this chapter and appendix V.

We agree that the PMAs have disadvantages compared to nonfederal utilities, and we have more fully reflected those in this chapter. For example, we added the Hoover Dam Visitor Center as a nonpower cost that Western must recover through rates. However, we do not agree with the PMAs' statement that our draft report said that irrigation assistance is a large subsidy paid by Western's customers. Our draft report stated that "as of September 30, 1995, according to Western, about $32 million of the total $1.5 billion of total irrigation debt has been recovered through electricity rates." To the extent that Western actually repays this irrigation debt, the power users are subsidizing irrigators. The billions of future irrigation investments that are not even in service are not costs that have been incurred, and it is questionable whether they ever will be incurred. To the extent that these planned future costs are included in Western's power repayment studies and impact current rates, the actual application of any relevant power revenue would be to other appropriated debt. We believe that 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.

The PMAs stated that Southwestern's inclusion of future replacement costs in its current repayment study results in its rates being 10 to 15 percent greater than they would otherwise be. We do not agree with this statement. The actual application of the revenues generated by inclusion of these costs in current rates has been to current year capital appropriations or other appropriated debt. As a result, Southwestern has been able to pay off most of its recent, higher interest debt and currently has a weighted average interest rate of 2.9 percent compared to 4.4 percent for Southeastern and 5.5 percent for Western. In addition, as discussed in chapter 3, Southwestern has reduced its balance of appropriated debt from $769 million at September 30, 1991, to $686 million at September 30, 1995. Thus, we believe that Southwestern has managed its appropriated debt using sound business principles and has minimized its interest expense that must be recovered through rates.

Another disadvantage cited by the PMAS relates to tentative project cost allocations. The PMAS stated that the tentative cost allocations may very well be higher, as in the case of the Clarence Cannon Project, than the final allocated costs. According to Southwestern's 1995 annual report, there are four projects that still have tentative allocations. Southwestern states in this report that "[T]he amount of adjustments that may be necessary when final allocations are approved for these projects is not presently determinable."

Because final allocations can either increase or decrease the percentage of costs allocated to power, the net effect of changes to allocations will not be known until all are finalized. Therefore, we do not believe that these tentative allocations represent a disadvantage to the PMAS.

Objectives, Scope, and Methodology

The Chairman, Subcommittee on Water and Power Resources, House Committee on Resources, and the Ranking Minority Member, House Committee on Resources, asked us to review several issues relating to Southeastern, Southwestern, and Western. The primary focus of our review was to determine whether all power-related costs incurred through September 30, 1995, have been recovered through the PMAS' electricity rates (chapter 2 and appendixes III and IV); whether the financing for power-related capital projects is subsidized by the federal government and, if so, to what extent (chapter 3); and how these PMAS differ from nonfederal utilities and the impact of these differences on power production costs (chapter 4 and appendix V). In addition, we were asked to provide information on FERC oversight of the PMAS (appendix VI). The following sections detail the methodologies used in our analyses.

Assessing Whether PMA Rates Recover All Power-Related Costs

To assess whether PMA rates recover all power-related costs, we reviewed appropriate legislation affecting the three PMAS, including the Flood Control Act of 1944, Reclamation Project Act of 1939, and applicable federal guidance. The acts discuss cost recovery in general, but do not specifically define the costs that must be recovered. The Secretary of Energy has set PMA cost recovery and accounting policy in DOE Order RA 6120.2, which we reviewed in detail. To define the full costs associated with producing and marketing federal hydropower, we reviewed Office of Management and Budget (OMB) Circular A-25, 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 SFFAS No. 4. These criteria indicate that the full cost of the electricity sold by the PMAS is the sum of all direct and indirect costs incurred by the operating agencies to produce the power, the costs incurred by the PMAS to market and transmit the power, and the costs incurred by any other agencies to support the operating agencies and PMAS.

To get an understanding of the PMAS' financing and the types of costs incurred, we reviewed the 1995 and 1994 annual reports of Southeastern, Southwestern, and Western. The financial statements included in the annual reports were audited by KPMG Peat Marwick LLP (KPMG), an independent public accounting firm. KPMG was hired by the DOE Inspector General to perform the audits of the PMAS. The KPMG audits of the PMAS are conducted in accordance with private sector and government auditing standards. On the basis of its audits, KPMG issues opinions on the fairness of the PMA financial statements and the adequacy of PMA internal controls and compliance with laws and regulations. KPMG issued unqualified opinions for 1995 and 1994 for Southeastern, Southwestern, and Western financial statements, indicating that they are fairly stated in all material respects. While it was not within the scope of our work to assess the overall quality of the auditors' work, we reviewed selected 1995 and 1994 KPMG audit workpapers to obtain background information. We met with KPMG and DOE Inspector General staff to discuss the financial audits. Throughout our report, where appropriate, we used audited numbers from the PMAs' 1995, 1994, and earlier annual reports.

We interviewed numerous officials at the PMAs and the operating agencies in the finance and rate-setting functions. We provided questions to each of the respective groups relating to cost recovery and other matters addressed in our report. We analyzed data provided to us by the PMAs and operating agencies to determine which costs are and are not fully recovered through rate charges. We did not assess the reasonableness of the methodologies used in developing the operating agency cost allocation formulas that are established for each project. In addition, the unrecovered 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 unrecovered costs that did not come to our attention during this review.

Assessing the Recovery of Pension and Postretirement Health Benefits

To assess whether pension and postretirement health benefits were fully recovered by the PMAs through rate charges, we consulted with representatives from the Office of Personnel Management, Office of Actuaries. We also reviewed KPMG's 1995 and 1994 reports on compliance with laws and regulations. We determined that certain Civil Service Retirement System (CSRS) pension and all post-retirement health benefits for current employees were not being recovered.

To calculate these unrecovered costs, we reviewed SFFAS No. 5, which requires all federal agencies, including PMAs, to record the full cost of pension and postretirement benefits in financial statements beginning in fiscal year 1997. SFFAS No. 5 prescribes that the aggregate entry age normal (AEAN) actuarial cost method be used to calculate pension expenses and accrued actuarial liabilities for pension benefits. 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." We consulted with OPM's actuaries 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 1995 and the cumulative unrecovered cost (unfunded liability) as of September 30, 1995. For CSRS employees, OPM reported that, in 1995, 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 each CSRS employee's annual salary. This 11.14 percent funding deficiency is applicable to the PMAs. To calculate the difference between the full (normal) cost for CSRS pensions and the amount employees and the federal agencies contributed, we did the following:

- estimated the number of PMA and operating agency employees involved in producing and marketing power for each of the three PMAs, based on information provided by the PMAs and operating agencies;
- estimated the number of those employees covered by the CSRS, based on governmentwide information provided by OPM on the percentage of employees covered by CSRS;
- multiplied that number by the average salary[1] 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 agencies would have had to contribute to fully fund CSRS pension benefits earned in fiscal year 1995.

To determine the cumulative unrecovered costs, under the AEAN method, for future CSRS pensions, we estimated the total accrued actuarial liability, which is equal to the present value of the total expected future benefit obligation less the present value of the future entry age normal cost contributions. To estimate the total cumulative unrecovered costs, we

[1]We obtained actual salary information for the PMAs. For the operating agencies, we used governmentwide average salary information for CSRS employees, which we obtained from OPM.

multiplied the accrued actuarial liability to payroll ratio (5.916), which was provided by OPM, by the estimated gross CSRS payroll associated with power production and marketing for the PMAs and operating agencies.

To estimate the funded portion of the accrued actuarial liability, we multiplied the asset to payroll ratio (2.085), also provided by OPM, times the estimated gross CSRS payroll associated with power production and marketing for the PMAs and operating agencies. We subtracted the funded portion from the total accrued actuarial liability to obtain an estimate of the cumulative unrecovered costs as of the end of fiscal year 1995.

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. The PMAs do not recover this cost from ratepayers. To calculate the amount of the unrecovered power-related costs for fiscal year 1995, we again used the AEAN method, which is prescribed by FASAB for estimating postretirement health benefits costs. We estimated the number of PMA and operating agency employees involved in producing and marketing power for each of the three PMAs. We multiplied this number for each of the PMAs by the 82 percent governmentwide health benefits plan participation rate, which we then multiplied by $1,973 (OPM's estimate of the annual normal cost for postretirement health benefits per participating employee). The result of this calculation approximates the normal cost of postretirement health benefits for fiscal year 1995 and the amount the agencies would have had to contribute to fully fund postretirement health benefits earned that year. To determine the cumulative unrecovered costs for postretirement health benefits, under the AEAN method, we multiplied the number of power-related personnel times the 82 percent participation rate and then times $26,336 (OPM's estimate of the cumulative unrecovered cost per employee as of the end of fiscal year 1995).

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

Assessing the Recovery of Other Costs

Information on recovery of costs relating to the Russell Project, Truman Project, Washoe Project, Mead-Phoenix Project, and Western's Abandoned Transmission Line was obtained by analyzing the PMAs' annual reports and other information provided by the PMAs and operating agencies. For the Russell Project, we reviewed records of congressional hearings on the project back to its initial approval in the 1960s.

To identify the portion of power-related capital costs allocated to incomplete and infeasible irrigation facilities at Pick-Sloan, we used (1) cost reports and estimates of the power requirements for irrigation facilities prepared by the Bureau of Reclamation, (2) cost allocation percentages prepared by the Bureau of Reclamation and Corps of Engineers, and (3) reconciliations prepared by Western of Western's Power Repayment Studies and the Bureau's Statement of Project Construction Cost and Repayment as of September 30, 1994.

To identify the portion of the Corps' power-related 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' annual O&M expenses based on the planned rather than the actual use of the irrigation facilities.

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 that some environmental costs are included in rates, but could not determine whether all such costs are included. To obtain the data necessary to make this determination would have required audit work which was beyond the scope of the assignment.

Determining Whether PMA Financing Is Federally Subsidized

For the purposes of this report, we defined the financing subsidy as the difference between Treasury's borrowing cost and the interest paid by the three PMAs to Treasury. Treasury's borrowing cost is particularly relevant because the federal government has had debt outstanding since before 1940—before the oldest PMA appropriated debt still outstanding—and has had a deficit every year since 1969. Thus, the federal government has had to issue debt to extend financing to the PMAs. There are three main aspects of the subsidy to the PMAs, although not all PMA debt has each of these elements. One is the difference between the PMA borrowing rate and the closest match of Treasury borrowing in terms of maturity at the time of the appropriation. The second is the PMAs' ability to repay the highest interest-bearing appropriated debt first. 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. Another factor is that PMA appropriated debt has maturities of up to 50 years, which is beyond the maximum maturity of Treasury bonds. Thus, if PMAs do not pay off appropriated debt within 30 years, Treasury would have to refinance its corresponding debt.

Because the data are not available to calculate the total subsidies for each loan in a way that fully accounts for all of the aspects of the subsidy, we developed an alternative method to estimate the 1995 financing subsidy. Specifically, 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 1995. We then multiplied the amount of appropriated debt outstanding by the average interest rate paid by the PMAs. Finally, we subtracted the estimated interest paid by the PMAs at their average interest rates from the estimated interest paid by Treasury on the same amount of debt.

Since Treasury does not match its borrowing with the PMAs' appropriated debt financing, the average interest rate on Treasury's entire bond portfolio best reflects its cost of funds. The bond portfolio average interest rate includes bonds with varying maturities up to 30 years. Treasury's bond portfolio average interest rate of 9.1 percent was obtained from the Monthly Statement of the Public Debt of the United States as of September 30, 1995. This document is published by the Bureau of Public Debt, Department of Treasury.

To illustrate the historical spread between the PMAs' cost of funds on appropriated debt and Treasury's bond portfolio, we compared the average interest rate Treasury was paying on its bond portfolio outstanding at the end of fiscal years 1952 to 1995 to the average interest rates paid by PMAs on their appropriated debt balances in the same years. We obtained data on levels of appropriated debt and weighted average interest rates associated with that debt from the PMAs. In some years adjustments to historical financial records had occurred, causing significant fluctuations in calculated interest rates; in these instances, we averaged the calculated interest rates over the period of fluctuation. Sufficient data were not available to identify the weighted average interest rates in fiscal years 1952 to 1985 for projects now serving Western. During this period, interest rates ranged from 0 percent on some minor projects in the early 1950s to 12.375 percent in fiscal year 1985. Western believes that on a consolidated basis for all projects, 3 percent represents a reasonable weighted average interest rate on appropriated debt for fiscal years 1952 through 1985. To identify the average interest rates paid by Western for fiscal years 1986 through 1995, we divided Western's annual interest on federal investment by the average outstanding appropriated debt during the year. Because of various adjustments to the annual interest expense, Western's interest expense and resultant average interest rates fluctuated significantly during this period. To show the trend line for Western's interest rates for fiscal years 1986 through 1995, we estimated the trend by plotting interest rates using the above calculations and using the 5.5 percent average for 1995 as the end point.

To compare Treasury's cost of funds to the new DOE policy rate for the years 1983 through 1995, we compared Treasury's yield rate on 30-year bonds issued each year to the average interest rates the PMAS were generally required to pay on new financing received from Treasury. We analyzed this time period because DOE's policy changed in 1983 to bring the cost of financing new PMA appropriated debt in line with Treasury market interest rates.

Our calculation of the financing subsidy does not include the impact of other forms of subsidy such as the difference between Treasury debt being compounded semiannually versus PMA debt being compounded annually. Our estimate of the subsidy also does not consider the impact that the risk of hydropower projects might have had on the PMAS' interest rates if they had been financed in the private market rather than through Treasury.

We calculated the total outstanding PMA appropriated debt as of September 30, 1995, using audited financial statements and power repayment studies. Western's appropriated debt included its deferred payments. We also calculated the PMAS' weighted average interest rates using data from the PMAS' audited financial statements and other data we received from the PMAS. We obtained the concurrence of PMA representatives as to the accuracy of our calculations of overall PMA debt as well as the weighted average interest rate calculations.

To help ensure that our methodology was reasonable, we spoke to representatives of OMB, Treasury, and the Congressional Budget Office. We also reviewed a report by the Energy Information Administration (EIA), an agency of the federal DOE, entitled Energy Subsidies: Direct and Indirect Interventions in Energy Markets (SR/EMEU-92-02, November 1992). This report calculates an interest subsidy for the PMAS.

Comparing PMAs to Nonfederal Utilities

We assessed how PMAS' average revenue per kWh, operations, tax status, accounting, rate-setting, and financing compared to the electric utility industry and focused our efforts on reasons why PMA power production costs were substantially lower than those of POGS and IOUS. We determined that IOUS and POGS were the appropriate "industry group" to compare to PMAS because they generate and transmit electricity and sell some power at wholesale. We did not include non-generating publicly owned utilities or rural electric cooperatives because these utilities generally buy electricity wholesale from a generating utility and sell the electricity retail. They ordinarily have no generating assets and thus are not comparable from an operating or financial perspective. Although we believe IPPS pose a competitive threat to PMAS, we excluded them from our comparison because IPP revenue per kWh and other relevant information was not readily available for 1994.

We compared the average revenue per kWh for Southeastern, Southwestern, and Western to the average revenue per kWh of nonfederal utilities. To do so, we divided the revenue from the sale of wholesale electricity by the total wholesale kilowatthours sold. We did our comparison on sales for resale (wholesale sales) because the three PMAS are almost exclusively wholesale electricity suppliers. A minor portion of Western's and Southwestern's sales are to end users—federal and state agencies. These sales are included in the calculation of average wholesale rates but have no impact on the average revenue per kWh. We did not perform a detailed electricity rate comparison of PMAS and nonfederal utilities. However, we believe that our comparison of average revenue per kWh is a strong indicator of the PMAS' relative power production cost and overall competitiveness compared to other utilities. We performed the computations for each of the PMAS using 1994 annual reports because this corresponded to the industry-wide data we had available for the POGS and IOUS. We obtained average revenue per kWh information by NERC region for POGS and IOUS from the American Public Power Association (APPA) and EIA, respectively.

To assess the similarities and differences between PMAS, IOUS, and POGS, we contacted two IOUS and two POGS in each of the PMA service areas. All 12 utilities that we contacted had some hydroelectric generating facilities. We gathered data from these utilities on their operations, accounting and rate-setting practices, financing, and rate oversight. We gathered similar data from the PMAS. To corroborate the information obtained from individual IOUS and POGS, we gathered similar information from and met with the Edison Electric Institute (EEI) and APPA to discuss these comparisons and the other components of our report.

To illustrate the key differences between PMAS, POGS, and IOUS, we prepared several ratios for fiscal year 1994. Information for POGS and IOUS was obtained from the EIA. These ratios were computed as follows.

- Net generation of power represents the percentage of each fuel source used to produce electricity. “Other utilities” encompasses both IOUS and POGS. Data were provided by EIA on total net generation by fuel source.
- Investment in utility plant per megawatt of generating capacity was calculated by dividing gross utility plant and CWIP by total megawatts of installed capacity. We did not include regulatory assets in our calculation. A downward adjustment was made to Southwestern’s available generating capacity because the Truman plant is operating with significantly reduced capacity due to environmental problems. In addition, the generating capacity relating to Russell’s inactive units was not included in Southeastern’s calculation. This ratio illustrates the relative cost of construction for generation and transmission plants.
- Fuel costs as a percentage of revenue were calculated by dividing total fuel cost by operating revenue. Data were provided by EIA.
- Leverage ratios were calculated by dividing long-term debt by total net assets and interest on long-term debt by operating revenue. Long-term debt for the POGS includes bonds and advances from municipalities and others. The IOUS’ long-term debt includes bonds, other long-term debt, and advances from associated companies. Adjustments were made to long-term debt to account for unamortized premiums and discounts. The current portion of long-term debt was excluded from our calculation of long-term debt for the POGS and IOUS. No adjustment has been made for the current portion of the PMAS’ long-term debt because there is no debt repayment requirement until the final year of the repayment period. For Western, long-term debt includes debt related to third-party financing arrangements.
- Interest on long-term debt to operating revenue was calculated by dividing total gross interest expense by operating revenue. Gross interest expense includes capitalized interest. For Western, interest expense includes third-party financing interest.

To determine the characteristics of FERC oversight and to identify similarities and differences between the rate approval and oversight process for PMAS and IOUS, we interviewed FERC representatives in various divisions of the Office of Electric Power Regulation. We asked for descriptions of the processes that each type of entity must submit to in order for a rate change to take place. We also discussed the basis for approving or disapproving rate changes requested by each type of utility.

Organizations and Groups Contacted

Federal Entities

Department of Energy
Energy Information Administration
Federal Energy Regulatory Commission
Department of Treasury
Department of the Interior
Bureau of Reclamation
U.S. Army Corps of Engineers
Office of Management and Budget
Congressional Budget Office
Office of Personnel Management

Bond Rating Agencies and Financial Analysts

Fitch Investors Service, Inc., New York, NY

Independent Public Accounting Firm

KPMG Peat Marwick L.L.P.

Electric Utilities or Holding Companies

Southern Company, Atlanta, GA
Duke Power Company, Charlotte, NC
Crisp County Power Commission, Cordele, GA
South Carolina Public Service Authority (Santee Cooper), Moncks Corner, SC
Empire District Electric Company, Joplin, MO
Union Electric Company, St. Louis, MO
City of North Little Rock Electric Department, North Little Rock, AR
Grand River Dam Authority, Vinita, OK
Pacific Gas and Electric Company, San Francisco, CA
Montana Power Company, Butte, MT
Salt River Project, Tempe, AZ
California Department of Water Resources, Sacramento, CA

Trade or Interest Group Associations

American Public Power Association, Washington, DC
Edison Electric Institute, Washington, DC
National Independent Energy Producers, Washington, DC

Comments From the Three Power Marketing Administrations

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

September 4, 1996

Gene L. Dodaro
Assistant Comptroller General
Accounting and Information
Management Division
U.S. General Accounting Office
Washington, D.C. 20548

Dear Mr. Dodaro:

The U.S. Department of Energy (DOE) has requested that we respond directly to you with comments on the General Accounting Office's (GAO's) draft report entitled Power Marketing Administrations: Cost Recovery, Financing and Comparison to Nonfederal Utilities (GAO/AIMD-96-146), dated September, 1996. We appreciate the opportunity to comment and to suggest technical corrections to improve the accuracy and balance of the final report.

The comments in this letter reflect the views of the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration. The comments in this letter address what these agencies believe are the most important policy issues raised by the draft report. A more detailed set of comments that provides more specifics on various sections of the report is included as a separate enclosure.

GENERAL COMMENTS

See comment 1.

PMAs are Following the Law and Congressional Intent. It is very important that the final report give greater recognition to the fact that the power marketing administrations' (PMAs') current repayment and accounting practices are consistent with current law and Congressional intent when such legislation was enacted. The PMAs' cost recovery and financing practices presented in the draft report may, or may not, be good public policy in 1996 -- ultimately that is for Congress to decide. Nevertheless, they are current law or expressed Congressional intent, and the PMAs are bound to continue these procedures until the law directs otherwise. The final report should give more emphasis to this point.

See comment 1.

Congressional Action Needed for Policy Changes. Following directly from the previous point, if Congress decides that PMA repayment and cost recovery practices should be changed, legislation will need to be enacted in most cases. However, the draft report is silent on this point, See comment 1.

potentially leading readers to believe that administrative actions by the PMAs could implement any corrective actions deemed necessary. This is not true, by and large, as our subsequent comments make clear. Therefore, it is important that the final report clarify that changes to current practices will frequently require Congress to enact new legislation.

See chapter 4.

PMAs Are Not Truly Comparable to Other Utilities. In response to the Congressional request, GAO includes a chapter in its draft report on how the PMAs differ from other utilities and the impact of these differences on power production costs. However, the PMAs have unique characteristics that make certain comparisons against other utilities of limited value. Specifically, the PMAs do not have responsibility to meet load growth in their regions nor do they have the authority to acquire new firm power resources -- primary responsibilities of "traditional" utilities. The PMAs have a different mission. They were established only to market "surplus" hydropower from Federal water projects. This major difference makes it inappropriate to compare the costs of PMA hydropower against the coal- and nuclear-based power generated by other utilities. To the extent the PMA resource base is comparable to any other it is most similar to the low-cost hydroelectricity produced at Federal Energy Regulatory Commission (FERC) licensed facility. This point should be included in the Executive Summary.

See comment 2.

PMAs Did Not Make the Generating Investment Decisions. The PMAs do not generate the power they market. That function is generally the responsibility of the Army Corps of Engineers and the Bureau of Reclamation. The PMAs did not control the decisions about which Federal power generating investments to make -- these decisions were the responsibility of the Congress and the generating agencies. Therefore, the draft report's references to "Southeastern's project" or "Western's project" is misleading, because it implies that decisions about whether to make the generation investment were PMA decisions. The PMAs were simply responsible for marketing whatever power was produced once the project was constructed. The draft report should emphasize this fact.

See comment 3.

Executive Summary Needs More Balance. The draft report includes a number of caveats and explanations that have not been incorporated into the Executive Summary. This gives readers of the Executive Summary a misleading picture of what the body of the report says. We ask that more of these explanations be added to the Executive Summary in order to give readers a more balanced view of the report's findings. For example, the Executive Summary should cite several of the other reasons given in the body of the report for why the PMAs are low-cost power producers (e.g. relatively little new investment since no need to meet load growth).

See comment 1 and chapter 2.

COMMENTS ON CHAPTER 2: COST RECOVERY

The PMAs set their rates to collect all power-related costs as provided by law. We agree with the draft report that, by law, there are some power-related costs that are not fully recovered through rates. We believe an important distinction about cost recovery needs to be made in this chapter, however; and we disagree with certain of the draft report's findings about the five activities cited,

See chapter 2.

and believe other activities deserve additional explanation. Each of the five is addressed in turn, after our comments on "unrecovered" vs. "unrecoverable" costs.

Unrecovered vs. Unrecoverable Costs. The final report needs to be more clear about "unrecovered" costs, as opposed to "unrecoverable" costs. "Unrecovered" costs are those that have not been repaid to the Treasury at a point in time, but will be recovered in the future (e.g. Mead-Phoenix Transmission Line, "deferred payments"). "Unrecoverable" costs are those that have not, and will never be, repaid to the Treasury, at least under current law and/or policy. As our comments point out, some costs may be "unrecovered" to date, but are not "unrecoverable" over time.

The draft report's Executive Summary states that GAO was asked to address whether the PMAs' rates recover all power-related costs. This question does not specify a point in time; rather it asks whether PMA rates -- either today's rates or future rates -- leave any costs "unrecoverable". However, the chapter on cost recovery is not limited to unrecoverable costs, it also discusses costs that have not been recovered to date, even when such costs are included in power repayment studies and current power rates, and are scheduled for repayment in future years.

Using this broader definition of unrecovered costs, all unpaid investment would be considered unrecovered at any particular point in time. There is no conceptual difference between an investment cost that is scheduled to be repaid in the future and a "deferred payment", as long as the correct interest rate is assigned to each. The fact that the "deferred payment" is for an operating expense and an investment is a capital expense may be important for accounting purposes, but is not relevant for determining whether the cost is ultimately recoverable. Both are "unrecovered" at a particular point in time, but neither is "unrecoverable".

We recommend that Chapter 2 of the final report focus on costs that appear to be "unrecoverable" -- ie. costs that are not included in repayment studies -- since that appears to be the intent of the question. (Alternatively, if the Congressional requesters, in fact, want a broader discussion that includes costs unrecovered at any point in time, the Executive Summary should more clearly state the scope of the request.) The discussion of costs that are included in repayment studies and, hence, will be recovered through power rates eventually even though they have not been repaid to date (ie. "unrecovered" costs) should either be deleted or, at a minimum, the text should make clear this important distinction.

Civil Service Retirement and Health Benefits. The PMAs agree that the full cost of these benefits is not included in PMA power rates. The PMAs' ability to reimburse the Civil Service Retirement and Disability Fund (Fund) for these benefits is limited by statute. However, as the body of the report explains, in the long term Congress has already taken action to eliminate the cost underrecovery by requiring all new Federal employees hired after 1983 to join a different retirement system that has full cost recovery. Over time, this will reduce and eventually eliminate this cost underrecovery. This point should be added to the Executive Summary.

See chapter 2.

What is not stated in the draft report is that to deposit full cost reimbursement into the Fund will require Congress to enact new legislation. At present, the PMAs cannot deposit power revenues into the Fund to pay for unfunded employee retirement benefits. To do so would augment the annual appropriation made to the Fund, a violation of appropriations law. Of course, Congress could choose to direct the PMAs to deposit certain power revenues into the Fund, as is required of the Postal Service, by passing a law to this effect.

The PMAs also believe that the draft report's reliance on OMB Circular A-25 is improper. The current Circular does not apply when the amount to be priced is provided for by statute, Executive Order, or regulation, as is the case here. In addition, the version of OMB Circular A-25 that was in effect from 1959 through 1993 specifically excluded "fee aspects of certain water resource projects (power, flood control, and irrigation)."

Non-operational Project Investment. The draft report says that construction costs associated with currently non-operational facilities, such as a portion of the Army Corps of Engineers' Russell and Truman projects, are not being fully recovered and will likely never be recovered. The PMAs have several comments on this issue.

First, the fact that these projects are not operating now and, hence, are not included in the repayment studies, does not lead to the conclusion that they will never operate. When they do operate, their costs will be included in the appropriate repayment study and recovered over their repayment period, with interest, through power rates. Repayment may be deferred, but full cost recovery -- including recovery of interest during construction -- will eventually occur. (To our knowledge, all "in service" power investments are included in a repayment study unless Congress directed otherwise.) Therefore, it seems premature to assume these costs are "likely" to be unrecoverable.

An example of an abandoned power investment is the portion of Western's Pacific Northwest/Southwest Intertie Project where construction was started, but never finished. There is no direct legislative authority that allows Western to declare a power investment as permanently nonreimbursable or unrecoverable. Therefore, Western will include the cost of this project in the affected power repayment study. The inclusion of these costs will be fully disclosed in the public rate process and in the FERC review of the proposed power rate. It would certainly be appropriate for Western to bring the existence of such an abandoned investment to Congress' attention but, absent Congressional action, Western has no choice but to include the investment in the repayment study.

If the operating agency does not allocate the costs of an investment, such as the Russell Project generators, to the power function, then the draft report is correct in asserting that these costs would not be recovered through power rates. (Under existing law, only capital costs allocated to power, or Western's irrigation aid costs, are to be included in power rates.) The PMAs' actions in this situation would be governed by Statement of Financial Accounting Standard (SFAS) No. 71, as amended by SFAS Nos. 90 and 92. This is similar to the treatment both the FERC and

See chapter 2.

state public utility commissions give to utility investments that the commissions find not to be "used and useful". In these instances, the ratepayers of the utility are not required to repay the costs of unusable investments made by the utility; these costs are borne by the shareholders who own the utility. Similarly, in the case of the PMAs, the PMAs' ratepayers would not be required to repay costs for investments that will never be "used and useful". This similarity should be presented in the final report.

The draft report also mentions the possibility that inclusion of all power-related costs for certain facilities (e.g.. Washoe Project, Mead-Phoenix Transmission Line) may cause the power rate to exceed the market price for power, rendering the facility uneconomic and its costs "unrecoverable". While this can certainly occur at various points in time, as is evidenced by the Washoe Project, the key question is whether it is likely to occur over a facilities' entire repayment period. With the wide fluctuations in energy markets that have occurred over the past 25 years, the 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.

Hence, the PMAs agree that the potential exists for certain non-operable investment costs not to be recovered, but believe the final report requires more clarification along the lines presented here.

Suballocated Pick-Sloan Power Investment. The PMAs are in general agreement with the discussion of this activity in the draft report, but believe that two additional points need to be added.

Specifically, the final report should place greater emphasis on the fact that the methodology for cost allocations cannot be changed without Congressional approval. This means the current cost allocation, which makes certain costs unlikely to be recovered, cannot be remedied by administrative action. The PMAs and the operating agencies are following what they understand to be Congress' intent, and until Congress directs otherwise, they must follow existing law. As the GAO testimony entitled FEDERAL POWER: Recovery of Federal Investment in Hydropower Facilities in the Pick-Sloan Program (GAO/T-RCED-96-142) states on page 1, "Changing the terms of repayment to recover any of the $454 million investment would require congressional action."

Further, as the GAO testimony also states, "Recognizing that the program incorporates agreements reached decades ago, any changes between the program's power and irrigation purposes may also 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." The PMAs believe that a thorough cost reallocation of the Pick-Sloan Program would have to recognize changes in flood control, environmental, and recreational benefits from what was originally anticipated. It is possible that a portion of the $454 million would be reassigned to these other project purposes.

See comment 4.

Legislatively Excluded Environmental Costs. The PMAs agree with the draft report's discussion of these two activities. Unless legislatively directed otherwise, all power-related environmental costs are recovered through power rates.

See comment 5.

Western's "Deferred Payments". The PMAs reiterate that these costs may be "unrecovered" to date, but they certainly are not "unrecoverable" over time. In fact, these costs are an integral part of Western's present rates which includes the recovery of interest at current Treasury rates on the outstanding "deferred payments". The final report should reference Western's planned repayment schedule for such "deferred payments". In the past, the PMAs have successfully demonstrated their ability to repay "deferred payments" with interest.

COMMENTS ON CHAPTER 3: SUBSIDIZED FINANCING

See chapter 3.

The PMAs agree that certain unpaid investments for which the PMAs have repayment responsibility are charged an interest expense that is less than the Treasury's cost of borrowing at the time the investment was made.

The vast majority of this difference in financing costs is attributable either to Congressionally mandated interest rates being assigned to investments, or to the past use of an interest rate assignment methodology that failed to reflect the full cost of Treasury borrowing. It is important to point out that the latter practice was partially corrected in 1970, and completely corrected in 1983. Nevertheless, certain investments made prior to that time remain unpaid today and, hence, continue to be repaid at a rate below Treasury's cost of borrowing funds when the initial investment was made.

The PMAs have a major concern with Chapter 3, however. Specifically, the draft report's methodology for measuring the magnitude of Treasury's unrecovered financing costs.

The draft report attempts to quantify the magnitude of the financing cost differential by comparing the average interest rate on each PMAs' unpaid investment against the Treasury's current average interest rate on bonds outstanding. The PMAs believe this is an invalid measure because it 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 referenced in the report cannot refinance their unpaid investment at Treasury without Congressional action, as was done recently for the Bonneville Power Administration.)

Our concern may better be 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

See chapter 3.

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 receives a subsidy from 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 gets a subsidy from the lender whenever market rates for home loans rise above the homeowners' fixed mortgage rate. This does not seem reasonable, in our opinion.

The PMAs believe a more accurate methodology for determining the magnitude of the financing cost difference is to compare each investment's fixed interest rate against Treasury's cost of borrowing <u>in the year the investment is placed in service</u>. If there is a difference then an unrecovered financing cost to Treasury exists, but the amount of the unrecovered cost difference remains fixed for each year the investment remains unpaid.

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

The PMAs also disagree with the draft report's assertion that the Treasury's additional cost is caused, in part, by the DOE policy of allowing flexible repayment terms (e.g. paying highest interest rate investment off first.) As long as the interest rate assigned to each investment reflects the Treasury's cost of borrowing at the time, then the Treasury is kept whole and no additional cost is incurred. The report accurately points out that investor-owned utilities use "balloon" repayments, and that nonfederal utilities also pay off their highest interest rate debt first -- a good business practice for borrowers.

See chapter 4.

<u>COMMENTS ON CHAPTER 4: LOW COST POWER</u>

The PMAs agree with the statement in this chapter that the PMAs are low cost producers of electricity. In general, PMA customers are continuing to purchase our power, even though they could go elsewhere. This supports the GAO's finding.

We are concerned, however, that the draft report's use of average revenue per kilowatt-hour (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 <u>types</u> 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 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

See chapter 4.

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 a good measure.

Another concern is that the report gives greater focus to advantages enjoyed by PMAs without giving equal attention to other costs that PMA customers must repay that would not normally be charged to utility customers. While we are pleased that the draft report notes that aid to irrigation is a large subsidy paid by Western's customers, other examples that could be noted include future replacement costs, the Hoover Dam Visitor Center, 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. Further, tentative cost allocations may very well be higher, as in the case of Clarence Cannon Project, than the final allocated costs. We believe Chapter 4 and the Executive Summary would benefit by providing a more balanced description of the differences between PMAs and other utilities with regard to costs assigned for recovery and included in power rates.

CONCLUSION

The PMAs appreciate the opportunity to comment on this draft report. We hope you find these comments useful, and that the final report incorporates them. The GAO staff are to be commended for their hard work and diligence in tackling a complex and arcane subject. While the PMAs disagree, sometimes strongly, with certain of the draft report's interpretations and conclusions, the PMA staff appreciate the cooperation and professionalism of the GAO auditors with whom they interacted.

Sincerely yours,

Joel K. Bladow

Joel K. Bladow
Assistant Administrator
for Power Marketing Liaison

Enclosures

The following are GAO's comments on the PMAS' letter dated September 4, 1996.

GAO Comments

1. We have more clearly noted in our report that the PMAS are generally following applicable laws and regulations regarding cost recovery and financing of capital projects. However, determining whether the PMAS' practices are in accordance with law, or whether the Congress should make policy changes for repayment and cost recovery practices, was beyond the scope of this review.

2. We agree with the PMAS' comment and have modified the report where appropriate.

3. We have revised the executive summary in several places in response to the views of the PMAS that it provided insufficient balance. These revisions provide clarification of views expressed in the body of the report.

4. Our report identifies environmental costs that have been legislatively excluded from recovery. In addition, we determined that there are environmental costs that do get included in rates; however, we do not conclude that all power-related environmental costs, other than those legislatively precluded, are recovered through power rates. To have the data necessary to make this determination would have required audit work which was beyond the scope of the assignment.

5. We have revised our report to reflect that Western officials plan to recover a majority of deferred payments over time. Reviewing Western's future plans to recover deferred payments was beyond the scope of our review.

Estimated Unrecovered Pension and Postretirement Health Benefit Costs

The following two tables show GAO's estimates of the three PMAs' annual funding shortfalls and cumulative unrecovered costs associated with Civil Service Retirement System (CSRS) pension and postretirement health benefits. As discussed in chapter 2, the estimates include only current employees of the PMAs and operating agencies; they do not include retirees. The tables show the amounts for the PMAs, the operating agencies, and totals.

Table III.1: Estimated 1995 Pension and Postretirement Health Benefit Costs Not Recovered From Power Customers

Dollars in thousands

	Southeastern		Southwestern		Western		
	PMA	Operating agency	PMA	Operating agency	PMA	Operating agencies	Total
Pension amount (Percent of total)	$109 (1%)	$1,560 (15%)	$665 (6%)	$733 (7%)	$4,374 (42%)	$2,883 (28%)	$10,324 (100%)[a]
Health amount (Percent of total)	61 (1%)	1,005 (17%)	314 (5%)	472 (8%)	2,293 (38%)	1,919 (32%)	6,064 (100%)[a]
Total	**$170**	**$2,565**	**$979**	**$1,205**	**$6,667**	**$4,802**	**$16,388**

[a]Percentages may not total 100 due to rounding.

Source: GAO estimates based on information provided by the PMAs, operating agencies, and OPM.

Table III.2: Estimated Total Cumulative Unrecovered Costs for Pension and Postretirement Health Benefits as of September 30, 1995

Dollars in thousands

	Southeastern		Southwestern		Western		
	PMA	Operating agency	PMA	Operating agency	PMA	Operating agencies	Total
Pension amount (Percent of total)	$3,755 (1%)	$53,635 (15%)	$22,884 (6%)	$25,220 (7%)	$150,405 (42%)	$99,152 (28%)	$355,052 (100%)[a]
Health amount (Percent of total)	821 (1%)	13,411 (17%)	4,190 (5%)	6,306 (8%)	30,601 (38%)	25,612 (32%)	80,940 (100%)[a]
Total	**$4,576**	**$67,046**	**$27,074**	**$31,526**	**$181,006**	**$124,764**	**$435,992**

[a]Percentages may not total 100 due to rounding.

Source: GAO estimates based on information provided by the PMAs, operating agencies, and OPM.

Western Area Power Administration Deferred Payments

The following schedule provides detailed information about Western's deferred operating and maintenance (O&M) expense and interest expense payments by project since fiscal year 1975. Specifically, the schedule shows the year the payments were deferred, the type of payment deferred, the interest rates applicable to the deferred payment debt, the amount of the deferred payments, and the outstanding balance of the deferred payment debt as of September 30, 1995.

Table IV.1: Western's Deferred Payments for Fiscal Years 1976 Through 1995

Name of project	Year payment was deferred	Type of expense payment deferred	Interest rate (%)	Amount of deferred payment (in dollars)	Amount unpaid as of 9/30/95 (in dollars)
Pick-Sloan	1989	Interest	9.250	$8,040,310	$0
	1990	O&M	8.875	13,672,497	0
	1990	Interest	8.875	37,844,690	15,713,456
	1991	Interest	8.750	29,264,073	0
	1992	Interest	8.500	49,750,956	49,750,956
	1993	Interest	7.875	65,534,048	65,534,048
Total Pick-Sloan					**$130,998,460**
Fryingpan- Arkansas	1983	O&M	3.046	$1,935,826	$840,653
	1983	Interest	3.046	29,483	29,483
	1984	O&M	10.403	272,992	0
	1984	Interest	10.403	3,798,264	0
	1985	O&M	10.898	885,464	0
	1985	Interest	10.898	6,456,958	0
	1986	Interest	11.070	3,754,785	0
	1987	Interest	10.693	2,457,817	0
	1989	Interest	10.250	2,750,821	0
	1990	Interest	10.075	2,281,432	0
	1991	Interest	9.920	1,202,967	0
Total Fryingpan- Arkansas					**$870,136**
Central Valley	1976	Interest	6.625	$3,192,493	$0
	1976	O&M	6.625	22,477,513	0
	1977	Interest	7.000	5,401,178	0
	1977	O&M	7.000	27,940,904	0
	1978	Interest	7.000	7,361,506	0
	1978	O&M	7.000	15,160,032	0
	1979	Interest	7.500	9,476,885	0

(continued)

Name of project	Year payment was deferred	Type of expense payment deferred	Interest rate (%)	Amount of deferred payment (in dollars)	Amount unpaid as of 9/30/95 (in dollars)
	1979	O&M	7.500	16,657,212	0
	1980	Interest	8.000	11,730,666	0
	1980	O&M	8.000	19,231,204	0
	1981	Interest	8.500	18,532,437	0
	1981	O&M	8.500	37,147,233	0
	1982	Interest	9.000	17,615,141	0
	1983	Interest	9.500	5,078,253	0
	1989	Interest	9.250	8,288,907	0
Total Central Valley					**$0**
Washoe	1988	O&M	8.500	$99,412	$99,412
	1988	Interest	8.500	242,539	242,539
	1989	O&M	9.250	38,724	38,724
	1989	Interest	9.250	271,372	271,372
	1990	O&M	8.875	23,144	23,144
	1990	Interest	8.875	300,083	300,083
	1991	O&M	8.750	128,853	128,853
	1991	Interest	8.750	337,614	337,614
	1992	O&M	8.500	151,974	151,974
	1992	Interest	8.500	380,589	380,589
	1993	O&M	7.875	127,789	127,789
	1993	Interest	7.875	425,090	425,090
	1994	O&M	7.125	142,242	142,242
	1994	Interest	7.125	468,701	468,701
	1995	O&M	7.250	192,816	192,816
	1995	Interest	7.250	543,082	543,082
Total Washoe					**$3,874,024**
Collbran	1977	Interest	7.000	$189,794	$0
	1978	Interest	7.000	160,869	0
	1979	Interest	7.500	104,865	0
	1980	Interest	8.000	53,960	0
	1981	Interest	8.500	117,213	0
	1982	Interest	9.000	172,439	0
	1984	Interest	9.500	304,125	0
	1991	Interest	8.500	342,426	0
	1991	O&M	8.500	346,929	0
Total Collbran					**$0**

(continued)

Name of project	Year payment was deferred	Type of expense payment deferred	Interest rate (%)	Amount of deferred payment (in dollars)	Amount unpaid as of 9/30/95 (in dollars)
Colorado River Storage Project	1989	O&M	10.250	$10,775,262	$0
	1989	Interest	10.250	6,848,151	0
	1990	Interest	10.080	6,197,373	0
	1991	O&M	9.920	11,005,806	0
	1991	Interest	9.920	19,864,455	0
	1992	Interest	9.740	21,366,372	0
	1994	Interest	9.230	53,847,105	43,795,000
Total Colorado River Storage Project					**$43,795,000**
Provo River	1991	Interest	8.750	$487	$0
	1991	O&M	8.750	11,141	0
	1995	Interest	9.230	29,343	29,343
Total Provo River					**$29,343**
Rio Grande	1976	Interest	6.630	$244,589	$0
	1977	Interest	7.000	430,785	0
	1978	Interest	7.000	368,231	0
	1979	Interest	7.500	165,937	0
	1990	Interest	8.880	107,316	0
	1990	O&M	8.880	163,242	0
Total Rio Grande					**$0**
Seedskadee	1985	Interest	10.900	$1,716	$0
	1986	Interest	11.070	21,573	0
	1986	O&M	11.070	204,727	0
	1987	Interest	10.690	134,282	0
	1987	O&M	10.690	334,514	0
	1988	Interest	10.370	189,840	0
	1988	O&M	10.370	309,517	0
	1989	O&M	10.250	204,262	0
	1989	Interest	10.250	241,628	0
	1990	Interest	10.080	392,813	287,920
	1991	Interest	9.920	208,209	208,209
	1992	Interest	9.740	271,820	271,820
	1993	Interest	9.500	745,275	745,275
Total Seedskadee					**$1,513,224**

(continued)

Name of project	Year payment was deferred	Type of expense payment deferred	Interest rate (%)	Amount of deferred payment (in dollars)	Amount unpaid as of 9/30/95 (in dollars)
Boulder Canyon	1988	Interest	8.500	$2,586,667	$2,586,667
	1989	Interest	9.250	2,329,541	101,807
	1990	Interest	8.875	2,545,023	2,545,023
	1991	Interest	8.500	2,770,895	2,770,895
Total Boulder Canyon					**$8,004,392**
Parker-Davis	1992	Interest	7.875	$2,667,784	$2,667,784
	1993	O&M	7.875	1,836,554	769,893
Total Parker-Davis					**$3,437,677**
Intertie	1976	Interest	6.625	$1,796,982	$0
	1977	Interest	7.000	1,306,475	0
	1978	Interest	7.000	885,308	0
	1979	Interest	7.500	743,102	0
	1980	Interest	8.000	385,024	0
	1981	Interest	8.500	532,401	0
	1982	Interest	9.000	1,077,947	0
	1983	Interest	9.500	457,867	0
	1992	Interest	7.875	2,742,335	2,742,335
	1993	Interest	7.875	393,503	393,503
	1994	Interest	7.125	44,773	44,773
Total Intertie					**$3,180,611**
Overall Total					**$195,702,867**

Source: Data in this table was provided by Western and was not verified by GAO. The unpaid balance of $195,702,867 as of September 30, 1995, reconciles to the audited financial statements.

Comparison of Average Revenue Per kWh Sold Between PMAs and Other Utilities

This appendix shows a comparison of average revenue per kWh between PMAS, IOUS, and POGS. The 5-year comparison in table V.1 shows that the difference between the PMAS' and other utilities' average revenue per kWh has been consistently greater than 40 percent for 5 consecutive years.

Table V.1: Trend Analysis of Average Revenue per kWh of Wholesale Power Sold—1990 Through 1994

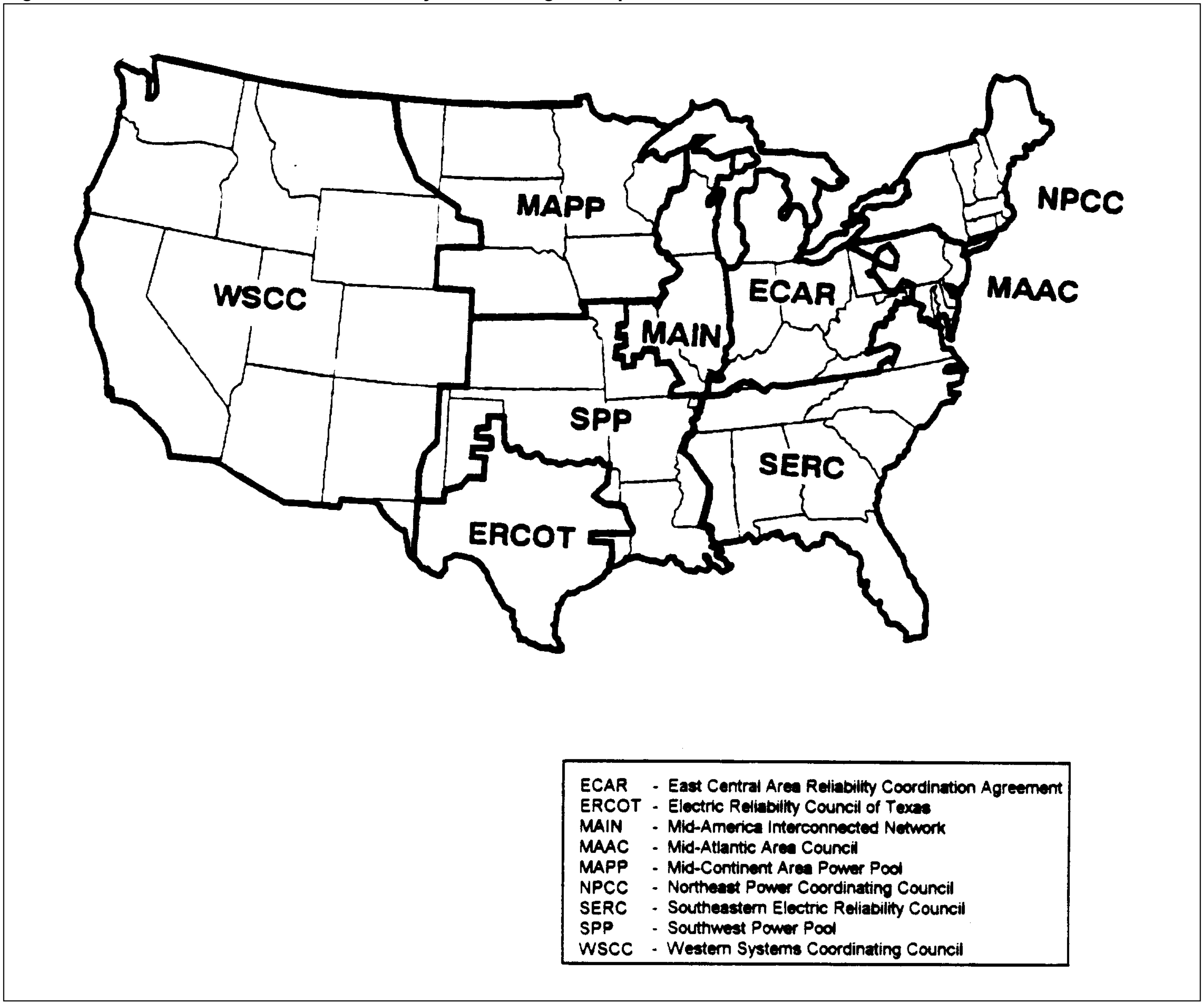
Cents/kilowatthour

	1990	1991	1992	1993	1994
Western	1.50	1.67	1.75	1.81	1.82
Southwestern	1.27	1.59	1.37	1.23	1.49
Southeastern	1.58	1.86	2.12	1.89	1.98
IOUs	4.17	3.58	3.57	3.40	3.50
POGs	3.78	3.78	3.90	3.80	3.90

Source: PMA Annual Reports and Financial Statistics of Major U.S. Investor-Owned Electric Utilities, Energy Information Administration, DOE.

Figures V.2 through V.9 in this appendix also show a comparison of average revenue per kWh for each of the PMAS' 17 rate-setting systems to the relevant North American Electric Reliability Council (NERC) region. 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 graphic. Figure V.1 shows the nine NERC regions.

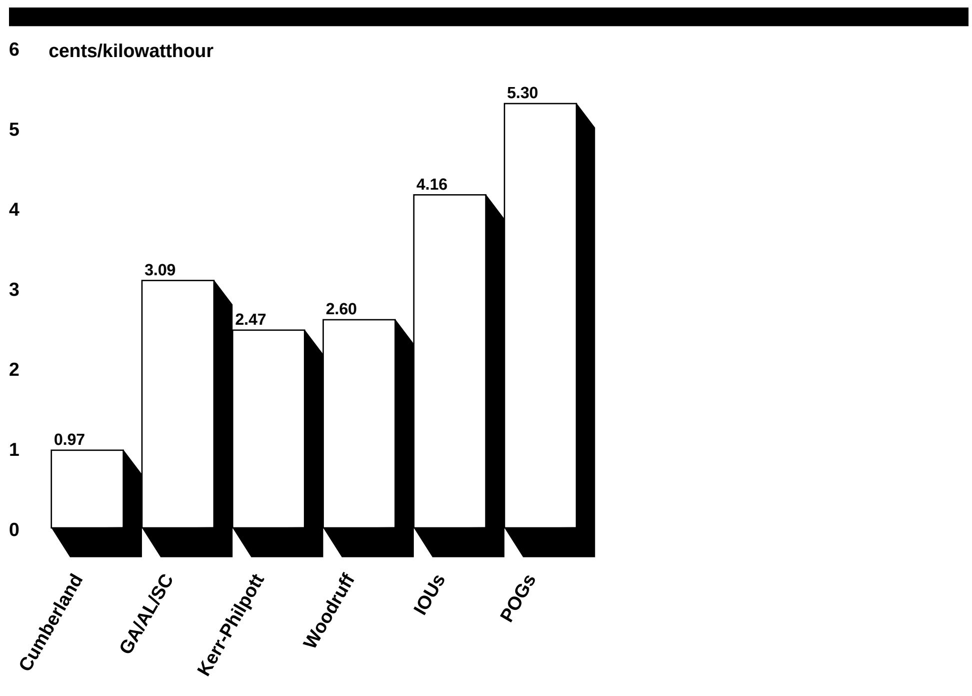
Figure V.1: North American Electric Reliability Council Region Map for the United States



Source: North American Electric Reliability Council.

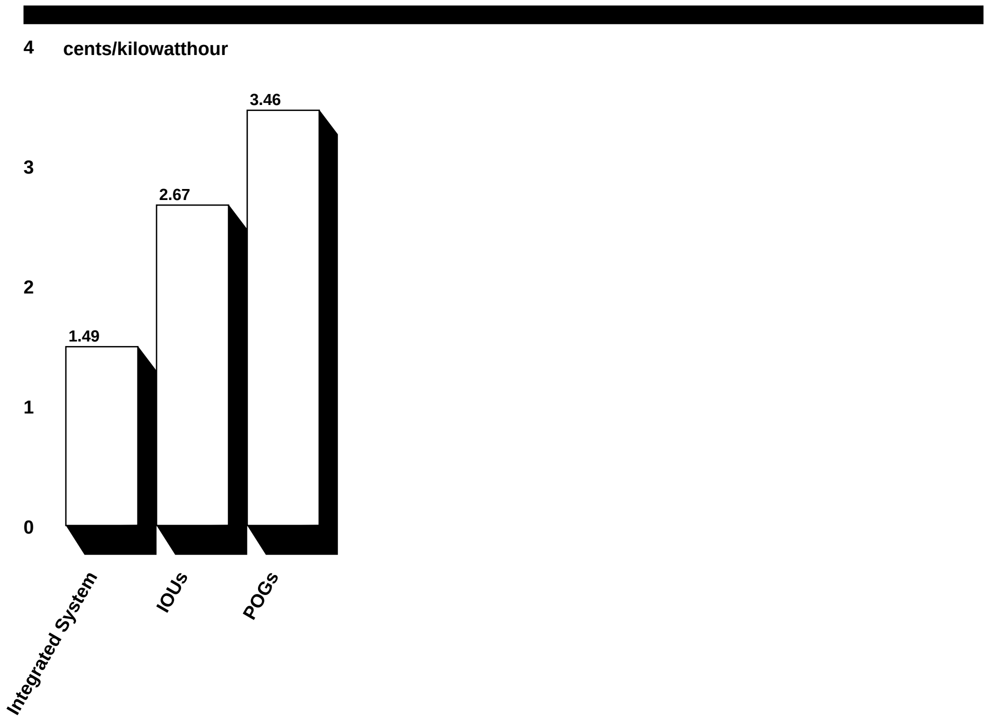
The remaining figures in this appendix show the 1994 average revenue per kWh for each of the three PMAs' rate-setting systems compared to the average revenue per kWh for IOUs and POGs for 1994 for each of the NERC regions in which the PMA rate-setting systems market power.

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



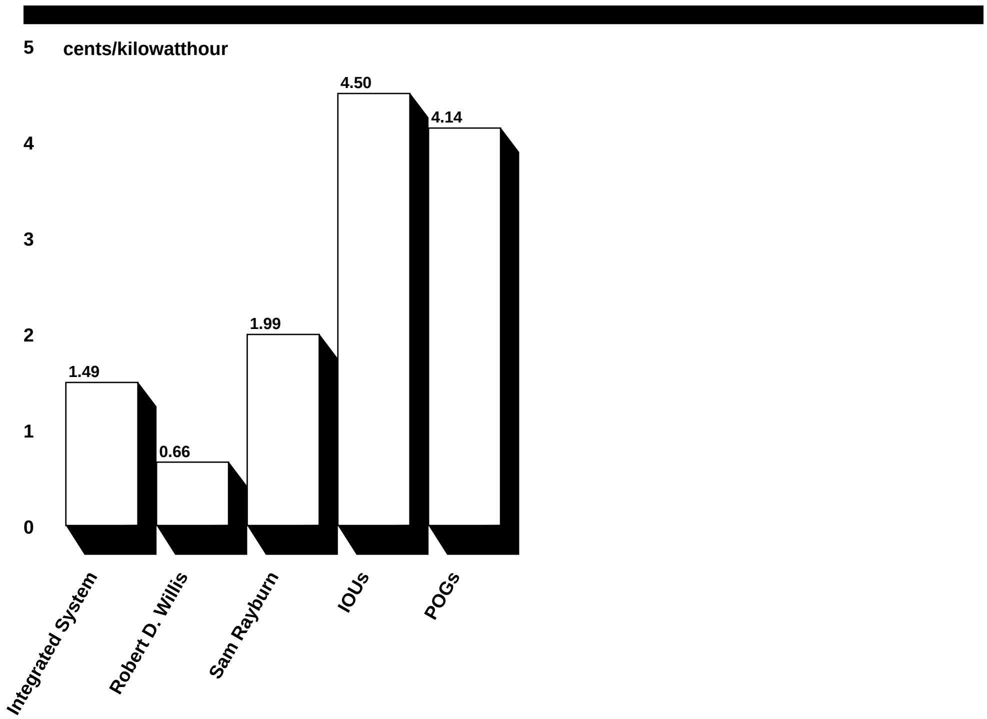
Source: Developed by GAO from Southeastern's 1994 annual report, EIA, and APPA.

Figure V.3: Comparison of Average Revenue per kWh by Southwestern Rate-setting System for the SPP Region



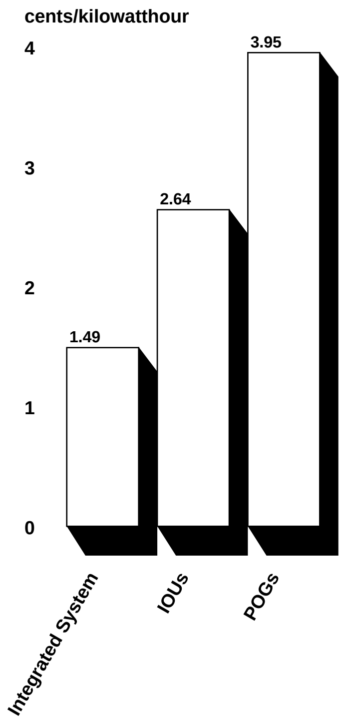
Source: Developed by GAO from Southwestern's 1994 annual report, EIA, and APPA.

Figure V.4: Comparison of Average Revenue per kWh by Southwestern Rate-setting System for the ERCOT Region



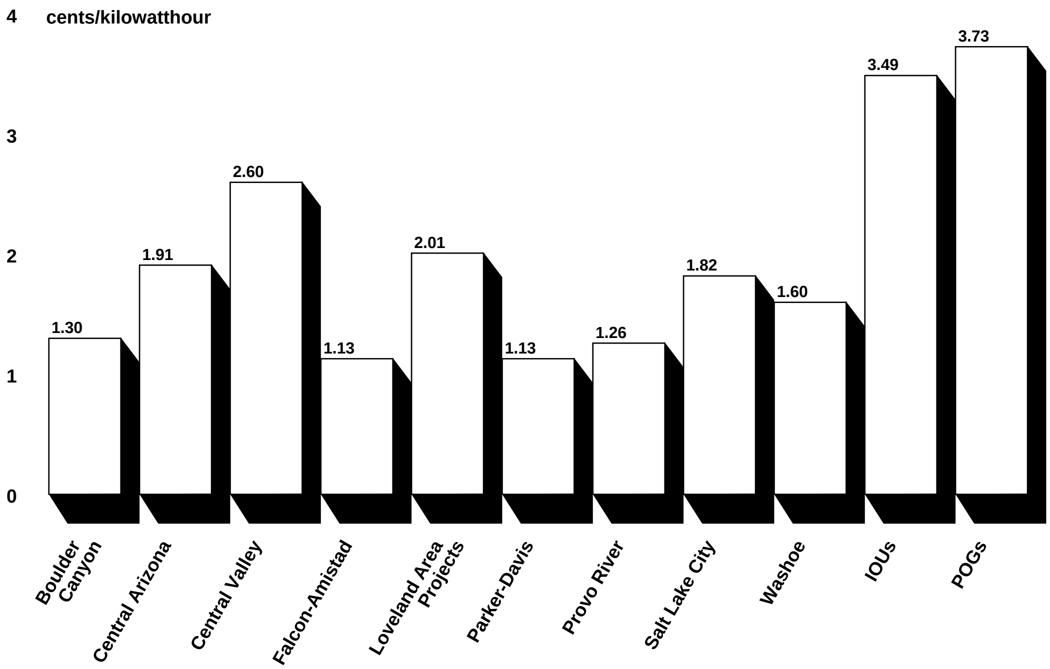
Source: Developed by GAO from Southwestern's 1994 annual report, EIA, and APPA.

Figure V.5: Comparison of Average Revenue per kWh by Southwestern Rate-setting System for the MAIN Region



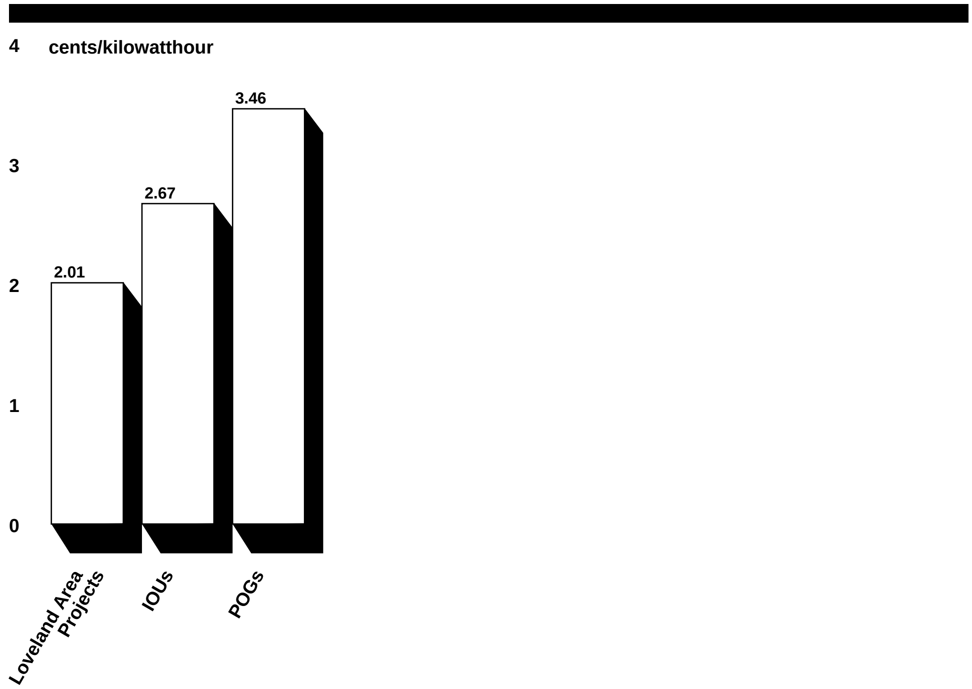
Source: Developed by GAO from Southwestern's 1994 annual report, EIA, and APPA.

Figure V.6: Comparison of Average Revenue per kWh by Western Rate-setting System for the WSCC Region



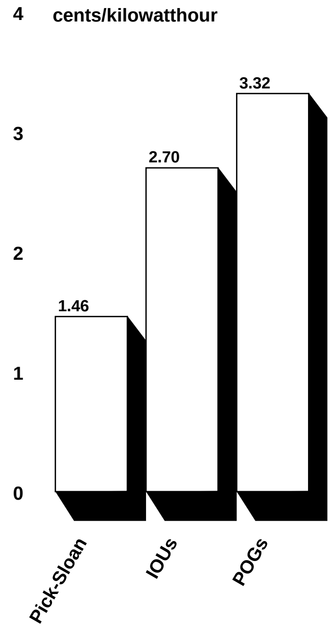
Source: Developed by GAO from Western's 1994 annual report, EIA, and APPA.

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



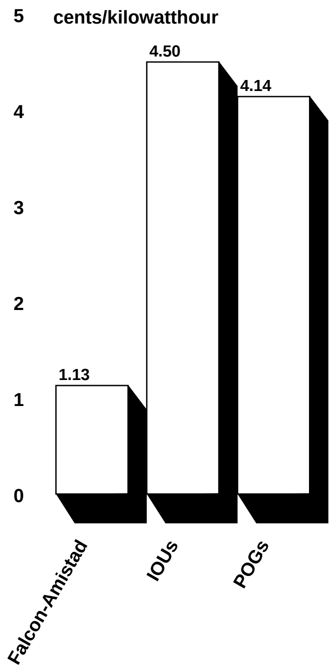
Source: Developed by GAO from Western's 1994 annual report, EIA, and APPA.

Figure V.8: Comparison of Average Revenue per kWh by Western Rate-setting System for the MAPP Region



Source: Developed by GAO from Western's 1994 annual report, EIA, and APPA.

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



Source: Developed by GAO from Western's 1994 annual report, EIA, and APPA.

Wholesale Rate Oversight/Regulation

The Federal Energy Regulatory Commission (FERC) oversees wholesale electric rates and service standards as well as the transmission of electricity in interstate commerce. FERC's jurisdiction of utilities does not extend to federal or municipal utilities. The Secretary of Energy, however, delegated to FERC the authority to approve the PMAS' rates.

FERC's involvement in IOUS' activities is broad. Any changes in contracts, rates, or services must be approved by FERC. IOUS must get approval from FERC for increasing rates in the event of increased costs, adding new construction to the rate base, mergers, and acquisitions. FERC's criteria for reviewing IOUS' rates is that they be just and reasonable and not unduly discriminatory or preferential. Factors that FERC considers in reviewing rates are competition and equal access. This is to provide assurance that the IOU does not exercise a monopoly in the sale or transmission of electricity and to determine their control over power resources in that area.

The Secretary of Energy has the authority to approve the PMAS' rates but delegated to the Deputy Secretary of Energy the responsibility to approve rates on an interim basis. Once the Deputy Secretary of Energy approves the rates, they go into effect on an interim basis and a rate application is submitted to FERC for final approval of the rates. Interim rates are in effect for an average of 4 months.

FERC's review process for the PMAS is restricted to the scope granted it by the Secretary of Energy. The review is limited to assessing:

(1) whether the rates are the lowest possible to customers consistent with sound business principles,

(2) whether the revenue levels generated by the rates are sufficient to recover the costs of producing and transmitting electric energy, and

(3) the assumptions and projections used in developing the rate components.

FERC may only affirm, remand, or disapprove the PMAS' rates. If FERC affirms rates, they are approved to be put into effect on a final basis. For a remanding of rates, the interim rate remains in effect, and the PMA must provide clarification to FERC on a designated issue. If the clarification provided by the PMA results in rates being affirmed, the interim rate goes into effect on a final basis. If FERC disapproves rates, it means FERC has found the submitted rate to be wrong. The interim rate remains in effect, but the PMA must submit a new rate application. The new rate application should compensate for any overcollection or undercollection as a result of the interim rate.

Limiting the review process further, FERC may reject the rate determinations only if it finds them to be (1) arbitrary, capricious, or in violation of the law, (2) violative of DOE regulations, or (3) violative of agreements between the PMA Administrator and the applicable power generating agency. FERC is prohibited from reviewing policy judgments and interpretations of laws and regulations made by the generating agencies.

There are indications that the rate review process by FERC for the PMAs has not been fully effective in ensuring that adequate revenue from power sales is earned to repay appropriations. For example, Western's Washoe Project had deferred payments related to interest and O&M expense of $3.9 million as of September 30, 1995.

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