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Report to Congressional Requesters

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FEDERAL POWER

Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry

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GAO
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Resources, Community, and
Economic Development Division

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The Honorable Don Young
Chairman, Committee on Resources
House of Representatives

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

This report discusses various issues concerning the role of certain power marketing administrations (PMA) and other federal agencies in restructuring electricity markets. We examined whether the government operates them and the related electric power assets in a businesslike manner and identified options that the Congress and other policymakers can pursue to address concerns about the PMAS' role in restructuring markets and about their management.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution of this report until 30 days from the date of this letter. At that time, we will send copies of the report to other appropriate House and Senate committees and subcommittees; interested Members of the House and the Senate; the Administrators of the Southeastern, Southwestern, and Western Area Power Administrations; the Commissioner, Bureau of Reclamation; the Director for Civil Works, U.S. Army Corps of Engineers; and other interested parties. We will also make copies available to others upon request.

If you or your staff have any questions, please call me at (202) 512-3841. Major contributors to this report are listed in appendix XI.

Victor S. Rezendes
Director, Energy, Resources, and
Science Issues

Executive Summary

Purpose

From the early 1900s through September 30, 1996, the federal agencies that generate and/or market electricity and that make or guarantee loans to finance improvements to electricity systems incurred a debt of about $84 billion.[1,2] Like the other federal agencies, the Southeastern, Southwestern, and Western Area power administrations—responsible for $7 billion of this debt—face an uncertain future as electricity markets restructure. The Chairmen of the House Committee on Resources and the Subcommittee on Water and Power asked GAO to focus on these three power marketing administrations (PMA) and to (1) examine whether the government operates them and the related electric power assets in a businesslike manner that recovers the federal government's capital investment in those assets and the costs of operating and maintaining them and (2) identify options that the Congress and other policymakers can pursue to address concerns about the role of the three PMAs in emerging restructured markets or to manage them in a more businesslike fashion. GAO's options also have implications for the Army's Corps of Engineers (Corps) and the Department of the Interior's Bureau of Reclamation (Bureau), which generate most of the power these PMAs market. As requested, the report also provides information about the Tennessee Valley Authority (TVA), Rural Utilities Service, and Bonneville Power Administration (Bonneville), which is contained in appendixes I, II, and III, respectively.

Background

Traditionally, electric utilities were regulated monopolies;[3] however, they are now being subjected to competition as retail and wholesale electricity markets restructure. Under the traditional compact between investor-owned utilities (IOU) and their state regulators, IOUs were guaranteed monopolies within their service areas. In return, IOUs built generating and other facilities to provide electricity to all existing and future customers in their service areas. Under this traditional regulation,

[1]Dollars for the net costs are in constant 1996 dollars, unless otherwise specified. The $84 billion power-related debt is either "direct" (owed directly to the Treasury—for example, the power marketing administrations' appropriations that are repayable through revenues earned from the sale of power) or "indirect" (owed to nonfederal parties—for example, the Tennessee Valley Administration's bonds that are held by nonfederal investors).

[2]Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses (GAO/AIMD-97-110, Sept. 19, 1997).

[3]Electric utilities function as monopolies and provide electricity to customers in their exclusive service areas. Three types of electric utilities exist: (1) investor-owned utilities, which constitute only about 8 percent of nation's 3,200 electric utilities but have over three quarters of the sales to ultimate customers; (2) 932 customer-owned rural electric cooperatives; and (3) 2,014 publicly owned utilities. In addition, nonutilities (or nonutility generators) exist that have no designated service areas and generate power which they sell in wholesale markets. They may generate power primarily for their own use (e.g., at petroleum refineries) and sell the excess power, or generate power primarily to sell it.

the states approved electricity rates that reflected the utilities' costs of building and operating their facilities and that included approved financial returns on these investments. Competition was introduced into wholesale electricity markets by the Public Utilities Regulatory Policies Act of 1978, which allowed entities that were not utilities to compete with utilities. Many of these nonutilities generate power using relatively inexpensive natural-gas-fired generating technologies. Subsequently, the Energy Policy Act of 1992 called for utilities to transmit power generated by outside entities to wholesale customers inside of their service areas, thus introducing competition. Retail electricity markets are also restructuring; at least 17 states are implementing measures that would allow customers to choose their electricity suppliers. According to the Department of Energy (DOE), by 2015, competition will cause retail electricity rates to drop by 6 percent to 19 percent below the level they would have been in the absence of competition.

The federal government began to market electricity after the Congress authorized the construction of dams and established major water projects, primarily in the 1930s to the 1960s. The Bureau and the Corps operate these projects to provide or manage water for such multiple purposes as irrigation, flood control, navigation, recreation, water supply, and environmental enhancement. These agencies also generate electricity at about 130 hydropower plants located at federal water projects. The PMAS[4] sell the power that is not used for projects' purposes[5] to "preference customers"—cooperatives and public bodies, such as municipal utilities, irrigation districts, and military installations. Historically, one of the important reasons for selling this power was to electrify portions of rural America that IOUs were reluctant to serve because of cost considerations. Rural America is now electrified. The federal government today markets about 10 percent of the nation's power through the PMAS as well as TVA—a wholly owned federal corporation that generates and markets federal power in Tennessee and parts of six other southeastern states.

The power the PMAS sell is relatively inexpensive. In 1990 through 1995, Southeastern's, Southwestern's, and Western's average revenues per

[4]In addition to Southeastern, Southwestern, and Western, Bonneville operates in the Pacific Northwest and is the oldest and largest PMA. The Alaska Power Administration (Alaska) is the smallest PMA. Unlike the other PMAs, Alaska generates its own electricity. The Congress passed a law in 1995 authorizing the divestiture of Alaska's power assets; the divestiture is ongoing.

[5]For example, for pumping water to fields being irrigated.

kilowatthour (kWh)[6] were about 40 percent less than the other power providers' average revenues. The PMAS' rates are generally to be set at the lowest levels practicable, consistent with sound business principles, while generally still recovering the costs of producing, transmitting, and marketing power, including the repayment, with interest, of the federal investment in the power generating facilities and other debt. However, under current federal laws, an applicable DOE order, and repayment practices, certain costs are excluded from the PMAS' rates, such as the full costs of (1) interest to finance the power facilities; (2) pension and postretirement benefits for the PMAS', the Bureau's, and the Corps' employees; and (3) the construction of a few federal power projects. Some costs to mitigate the environmental damages caused by certain federal water projects, including their hydropower plants, also must be excluded.[7]

Results in Brief

Although federal laws and regulations generally require that the PMAS recover the full costs of building, operating, and maintaining the federal power plants and transmission assets, in some cases federal statutes and DOE's rules are ambiguous about or prohibit the recovery of certain costs. As GAO reported in September 1997, for fiscal years 1992 through 1996, the federal government incurred a "net cost" of $1.5 billion from its involvement in the electricity-related activities of Southeastern, Southwestern, and Western. The $1.5 billion was the amount by which the full costs of providing electric power exceeded the revenues from the sale of power. In addition, the availability of federal power plants to generate electricity is below that of nonfederal plants because the federal plants are aging and because the federal planning and budgeting processes, as implemented by the Bureau and the Corps, do not always ensure that funds are available to make repairs when needed.[8] The resulting declines in performance decrease the marketability of federal power. To mitigate these funding delays, the Bureau, the Corps, the PMAS, and their preference customers have negotiated or are negotiating agreements whereby customers pay for needed repairs in advance. The net cost to the Treasury and the decreased generating availability of the federal power plants—when combined with the competitive pressures on all electricity

[6]A watt is the basic unit used to measure electric power. A watthour is equal to a watt of power applied for 1 hour. A kilowatthour (kWh) is 1,000 watthours.

[7]See GAO/AIMD-97-110. For example, Western incurred costs of $53.8 million in fiscal years 1992 through 1996 to buy power for its customers because the Shasta project in California released water to protect fisheries. However, the 1991 Energy and Water Development Appropriations Act specified that these costs not be allocated for repayment through PMA customers' electric rates.

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

suppliers to decrease their rates and the need to recoup some federal hydropower projects' environmental costs—create varying degrees of risk that some of the federal investment in certain hydropower plants and facilities will not be repaid. For example, although the recovery of most of the federal investment in Southeastern's, Southwestern's, and Western's hydropower-related facilities is relatively secure, up to $1.4 billion out of about $7.2 billion of the federal investment in the electricity-related assets of these PMAS is at some risk of nonrecovery. For example, at the Corps' power plants at the Truman project in Missouri and the Russell project in South Carolina, over $500 million of the federal investment to build these assets currently is not being recovered through the power rates charged by Southwestern and Southeastern, respectively. Under the PMAS' existing rate-setting practices, these costs cannot be placed into the rates until the pumpback units at the Russell project and the turbines at the Truman project come into service as designed. Because operation of these power plants would kill large numbers of fish, the affected units cannot be placed into service as intended until this issue is resolved. According to the Corps, repairs to these two projects are to be completed by the end of fiscal year 1999.

Three general options are available for the Bureau, the Corps, Southeastern, Southwestern, and Western to address their roles in emerging restructured electricity markets. First, the Bureau and the Corps could continue generating and the PMAS could continue marketing power as in the past. This option perpetuates the net costs to the government and does not decrease the risk that the federal investment in certain of the government's electricity-related assets will not be fully recovered. Nor does it resolve questions about the continued role of federal power in restructuring markets, such as why the government continues to provide power to rural areas that are already electrified and why it sells this low-cost power only to customers in the South and West. This option continues to balance the existing multiple uses of water and allows time for policymakers to consider changes that can be made to the operations of the Bureau, the Corps, and the PMAS.

Second, the current ownership structure could be maintained while improving how the federal assets are managed and operated, including making changes to better recover the operations and maintenance costs as well as the federal investment in the power assets. This option has many suboptions, such as revising the federal agencies' planning and budgeting processes to improve the timeliness and certainty of funding for repairs; modifying the PMAS' rate-setting and repayment methodologies to better recover costs; restructuring the hydropower program, perhaps in the form of federal corporations, to improve its efficiency; and freeing the federal agencies from certain legal and administrative requirements. Drawbacks include not resolving the concerns about the role of federal power in restructuring markets.

Third, the federal government could divest the PMAS; the PMAS and the generating assets; or the PMAS, the generating assets, and the dams and reservoirs. Any of these actions would end the government's role in selling power in a competitive market. Depending on the sale's terms and conditions and the price obtained, a divestiture may or may not recover the government's investment in hydropower-related assets. Divestiture is complex because steps would be needed to balance the multiple purposes of the water projects and to accommodate related interests. Also, the effect of a divestiture on the PMAS' customers' rates would need to be considered. Finally, some divestitures could result in sales proceeds that do not recover the federal investment. For example, if the government transferred some liabilities, imposed restrictions after a sale, or limited the availability of water to generate electricity, a lower price for the assets could result.

GAO's Analysis

Southeastern's, Southwestern's, and Western's Power Programs Operate at a Net Cost, Have Generating Assets That Need Repair, and Pose Some Risk That the Federal Investment May Not Be Repaid

As GAO recently reported, the federal program to generate and market power and to make or guarantee loans to rural utilities operates at a net cost of billions of dollars to the Treasury. For Southeastern, Southwestern, and Western, this net cost totaled about $1.5 billion in fiscal years 1992 through 1996 because these PMAS' power rates do not recover all of the costs associated with the production, transmission, and sale of power. It is important to note that the three PMAS were generally following applicable laws and regulations applying to the recovery of costs; however, in some cases, federal statutes and an applicable DOE order are ambiguous about or prohibit the recovery of certain costs. To mitigate the funding delays that characterize the agencies' planning and budgeting processes, the Bureau, the Corps, and the PMAS have instituted efforts to collect funding from preference customers to pay for needed repairs of the federal hydropower assets in a more timely and predictable fashion. For example, Western's preference customers have agreed to finance repairs at the Bureau's Shasta plant in California by depositing up to $21 million in an escrow account to pay for the work. According to Bureau officials, customers who contributed funds will be issued credits on their monthly power bills from Western, while those who did not contribute will not be issued these credits.

This $1.5 billion of net costs included net financing costs of about $1.2 billion. These net financing costs occurred mostly because (1) much of Southeastern's, Southwestern's, and Western's outstanding appropriated debt[9] was provided at low interest rates while the Treasury's financing costs for this money were higher and (2) these PMAs, under an applicable DOE order, generally repay debt with higher interest rates before repaying lower-rate debt from the Treasury, which causes the Treasury to incur additional, higher costs. Before 1983, the PMAs generally incurred appropriated debt at below-market rates. The average interest rate on the PMAs' outstanding appropriated debt (about 3.5 percent) is substantially below the average rate the Treasury has incurred (about 9 percent[10]) to fund federal programs. In addition, Southeastern's, Southwestern's, and Western's rates did not recoup about $82 million of the cost of providing retirement benefits to their and the operating agencies' employees and about $138 million in interest related to power generating projects that are incomplete, are under construction, or were canceled. A balance of about $157 million for other costs in a variety of categories was also not recouped.

The Bureau's and the Corps' power plants have become less available to generate electricity than those of other utilities,[11] which makes the PMAs' power less attractive to customers at a time when competition is giving them more opportunities to buy reasonably priced power from a variety of suppliers. Although power plants' maintenance needs differ by location, within the operating agencies federal power plants go off line for two

[9]GAO uses the term "appropriated debt" because the PMAs and TVA are required to repay appropriations used for capital investments, with interest. However, the Department of the Treasury does not technically consider these reimbursable appropriations to be lending.

[10]This rate is the weighted average interest rate on the Treasury's entire outstanding bond portfolio (10- to 30-year maturities) as of September 30, 1996. GAO used this interest rate because it reflects the Treasury's average interest rate on outstanding long-term debt and because this debt most closely matches the terms of the PMAs' appropriated debt.

[11]According to data provided by the Corps, its hydropower plants were available to provide power 92.9 percent of the time in fiscal year 1987 but only 87.9 percent of the time in fiscal year 1995. However, the availability of these plants improved to 88.4 percent in fiscal year 1996 and 89 percent in fiscal year 1997. The Corps attributes this improvement, in part, to $450 million committed to repair its hydropower assets from fiscal year 1993 through fiscal year 2007. The Bureau's plants were available only 83.4 percent of the time in 1994, compared with the industry's average of 89 percent. According to Bureau officials, the availability of the Bureau's plants over the last 3 years has improved over the average availability of the last 15 years.

basic reasons. First, the age of the plants (the Bureau's plants average about 50 years in service and the Corps' about 30 years) increases the need for repairs. Second, the federal planning and budgeting processes, as implemented by the Bureau and the Corps, do not always provide funding to repair the federal power assets when it is needed, delaying some repairs and also causing the power plants to become less available to provide power. Specifically, the Bureau's and the Corps' field locations identify improvements for, estimate the costs of, and develop the budget proposals for not only hydropower facilities but also other facilities, such as dams, irrigation systems, and recreational facilities. Given these competing purposes, repairs of hydropower facilities sometimes take lower priority than other items. Also, budget requests to fund hydropower repairs have been cut by 10 percent to 15 percent to reduce the federal deficit. In GAO's view, maintaining this power's availability is needed to ensure that the power revenues recover as much of the federal costs and investment as possible. Moreover, if the Congress and other policymakers decide to divest the federal power assets, then maintaining the power's availability could facilitate the divestiture; however, the government would not want to spend so much on repairing and upgrading its assets that the amount spent exceeded any increases in the sales proceeds or the value of those improvements.

The large, recurring net costs to the Treasury of operating the federal hydropower program, along with the decreased availability of the generating assets, contribute to the risk that the taxpayers' investment in the federal hydropower assets will not be recovered. Other factors, too, increase the risk of nonrecovery. One general factor is the onset of market competition, which is holding down market rates. At the same time, the PMAS' electricity rates at some projects face increased costs; these include (1) the costs of mitigating the damages to fish and wildlife habitat caused by generating hydropower and (2) purchasing power to sell to the PMAS' power customers when, to protect the environment, federal power plants reduce the electricity generated. In general, at Southeastern, Southwestern, and Western, most of the federal investment is relatively secure. Because these PMAS sell power at low rates, it is relatively easy to sell, and the resulting revenues facilitate the recovery of the federal investment. However, as GAO recently reported, up to about $1.4 billion of the investment in the hydropower-related assets of these PMAS (out of a total federal investment of about $7.2 billion in their power assets) is at some risk of nonrecovery. In addition to the previous examples of the Truman and Russell projects, for which over $500 million may not be recovered, about $464 million that the Bureau invested in power generating capacity and water storage within the Pick-Sloan Missouri Basin Program[12] may not be recovered without congressional action. These assets were designed to serve future irrigation projects, but under existing legislation, about $464 million cannot be recovered through Western's electricity rates until the projects come into service. However, according to the Bureau, these projects are infeasible and likely will never come into service.

Options Exist to Address the Federal Role in a More Competitive Market

Three general options exist to address the federal role in restructuring markets: (1) maintaining the status quo of federal ownership and operation of the power generating projects, (2) maintaining the federal ownership of these assets but improving how they are operated, and (3) divesting these assets.

Maintaining the Status Quo

Maintaining the status quo perpetuates the recurring net costs to the Treasury and the risk that some of the federal investment will not be repaid. In addition, this option does not resolve concerns about the continued role of federal power in restructuring electricity markets. Specifically, the government's power program has successfully electrified rural areas; therefore, an original justification for the government to provide power in these areas has passed. Moreover, one could question the equity of the PMAS' providing low-cost power to customers in 34 states primarily in the South and West but not to other areas. IOUS and other critics of the PMAS have also argued that, as federal agencies, the PMAS have advantages that the IOUS do not have. As GAO's work has shown, the PMAS have charged rates that do not recover all of the government's costs of generating, transmitting, and marketing power. Also, as federal agencies, the PMAS do not pay income taxes, are not overseen by state regulators, and have more flexibility to set rates than nonfederal utilities.

The status quo continues the federal role in balancing the multiple uses of water and allows policymakers time to study these issues before they change the operations and/or ownership of the water projects and power assets. How water is used affects wide geographic areas across state lines and has a significant impact on people's lives. It affects such things as how much water will be available to accommodate the expansion of metropolitan areas, how much water will be used to protect endangered species, and how much water will be needed to protect shellfishing—in

[12]The Program consists of 13 of the Corps' and the Bureau's hydropower plants and associated irrigation projects, among other assets, located in the northern basin of the Missouri River. Western sets rates that are designed to recover not only the federal capital investment in the power system, but also part of the federal investment in irrigation, as well as other costs.

Apalachicola Bay, Florida, for instance. The Bureau and the Corps generate power while balancing these impacts. Any decisions that federal policymakers reach about changing how power is generated or how the water projects are managed or owned will need to consider the impacts on the uses of the water and the beneficiaries of the projects.

Improving the Management of the Power Program Within Federal Ownership

Under the second option, the management of the federal power assets could be improved while they remain under federal ownership. Properly implemented, such improvements could help promote the recovery of the operation and maintenance costs of the power program as well as the federal investment in the power assets. It could also help prepare these assets for divestiture if the Congress decides to divest them. However, this option does not address the questions, previously discussed, about the federal government's participation in a commercial activity. Depending on how they are structured, some reforms may decrease opportunities for oversight by the Congress.

This option includes several suboptions. First, the Bureau's and the Corps' planning and budgeting processes could be revised to secure funding more quickly and predictably than is currently the case to repair the hydropower assets. The budgeting process is lengthy and, as described, has required cuts of 10 percent to 15 percent of the agencies' budget requests. Consequently, funding for repairs is uncertain and sometimes is not available when needed. One solution would be to institute revolving funds for the PMAs. Under this arrangement, a one-time permanent appropriation is replenished through revenues that are earned by selling power or other services and credited directly to a fund, instead of being replenished through annual appropriations. These funds, which could be used to pay for operations, maintenance, repairs, and replacements for the power plants and other assets, enable funding to occur that is not subject to the uncertainties of the operating agencies' budget processes. Funding for needed repairs is approved faster and is made available with more certainty, according to agency and PMA customer association officials. Several water projects that generate power now have revolving funds, which the Congress could extend to other projects. Also, under agreements with the agencies, the PMAs' customers can provide up-front funding for capital repairs and improvements. For example, the Bureau and Western have negotiated or are negotiating such arrangements at several water and hydropower projects involving tens of millions of dollars of funding for repairs.

Second, the Congress or the Secretary of Energy could change how the PMAS' revenue requirements and rates are established to more fully recover the costs of generating, transmitting, and marketing power. Where prudent, the Congress or the Secretary of Energy could direct or authorize the PMAS to charge higher rates to enable them to better recover costs and reduce the risk that the federal investment will not be repaid.[13] In fiscal year 1998, Southeastern, Southwestern, and Western are to take a step in this direction by beginning the process of recovering, through their rates, the full costs of the pension and postretirement health benefits of their employees. The Congress or the Secretary of Energy could also direct DOE to revise the methodology for the PMAS' repayment of their debt, thereby increasing the PMAS' electric rates, power revenues, the amount repaid to the Treasury, and the rate of repayment to the Treasury. Because the amount of hydropower generated can vary from year to year, federal laws and an applicable DOE order allow the PMAS to defer repayment of the annual expenses during some "low water years."[14] The PMAS also generally repay their highest interest-bearing debt first rather than the older lower-rate debt from the Treasury. Consequently, their electricity rates are lower than otherwise, with the older debt deferred. The repayment of the federal investment is also lower. This situation results in additional costs to the Treasury because interest rates on the outstanding federal investment are substantially below the interest rates the Treasury incurs to provide funding to the PMAS and other federal programs. Repaying the federal investment faster could decrease the Treasury's interest costs and could decrease the amount of investment at risk of nonrecovery. However, policymakers may need to consider the impact of any rate increases on the PMAS' customers.

Third, the Congress could also restructure the PMAS as federally owned corporations. With this action, the PMAS could finance repairs and improvements more expeditiously and predictably than under the federal budget process because the PMAS would self-finance and would require fewer external approvals and oversight. Establishing a government corporation could also serve as an interim step toward divesting the federal hydropower assets.

[13]It should be noted, however, that along with such factors as costs incurred to mitigate environmental impacts, these changes could place upward pressure on rates for some rate-setting systems to the point where they exceed regional rates. In a competitive market, any measure that increased the PMAs' rates would jeopardize the PMAs' ability to sell power and repay the federal investment.

[14]The amount of hydropower generated varies from year to year, given changes in water flows. Deferred amounts bear a current interest rate and are to be repaid on a priority basis before all other investment. Repayment is to be accelerated during good water years.

Finally, the PMAS, the Bureau, and the Corps could be exempted from certain legal and administrative requirements that, according to agency officials, cause them to operate inefficiently and can cause the PMAS' power rates to be higher than otherwise. According to a May 1996 study by Western, if the Congress had authorized Western to pay prevailing local wages for its service contracts in fiscal years 1992 through 1995, instead of the higher wages prescribed by law, it could have saved about $6.2 million per year.

Divesting the PMAs and Hydropower Assets

Under the third option, divesting the PMAS and federal power assets would eliminate the government's presence in a commercial activity and, depending on a divestiture's terms and conditions and the price obtained, could produce both a net gain and a future stream of tax payments to the Treasury. The Congressional Budget Office recently estimated that a sale of Southeastern, Southwestern, and Western and the related hydropower assets would result in revenues of between $8 billion and $11 billion; these revenues might not be enough to recover the government's investment in hydropower-related assets.[15] Divestitures of government assets have been accomplished recently in the United States and also overseas; GAO's March 1997 report concluded that divesting the federal hydropower assets would be complicated but not impossible.[16] Such a transaction would need to balance the multiple purposes of the water project as well as other claims on the water. The federal responsibility for balancing water use among the authorized purposes and other public policy goals would not necessarily end after a divestiture. Depending on the divestiture's conditions, balancing a project's purposes or accommodating other public considerations may affect a project's operation afterwards and thereby lead to continued liability for taxpayers.

Some of Southeastern's, Southwestern's, and Western's customers are concerned that a sale would significantly raise their rates—the PMAS' average revenues of under 2 cents per kWh were at least 40 percent less than the average revenues for nonfederal utilities in 1990 through 1995. Therefore, how a divestiture could affect preference customers' rates needs to be considered. In general, because most preference customers buy only a small portion of their total power from these PMAS, GAO estimates that most of them would experience relatively small changes in their wholesale rates. For example, if, after a divestiture, the rates for the PMAS' power increase to market rates, about two-thirds of these PMAS'

[15] Should the Federal Government Sell Electricity?,Congressional Budget Office, (Nov. 1997.)

[16] Federal Power: Issues Related to the Divestiture of Federal Hydropower Resources (GAO/RCED-97-48, Mar. 31, 1997).

preference customers would experience rate increases of 25 percent (roughly 0.5 cents per kWh) or less. If these preference customers passed their rate increases directly on to the end-users they serve, their average residential customers would experience increases in their electricity bills of no more than $4.17 per month.

However, some preference customers—in particular ones that purchase most of their power from the PMAS—could experience much larger increases. For example, in 1995, 35 percent of Western's preference customers purchased more than half of their electricity from the PMA. Correspondingly, GAO estimates that about one-fifth of Western's customers may see their rates increase by more than 75 percent. Similarly, about 27 percent of Western's preference customers would see rate increases exceeding 1.5 cents per kWh. However, although some preference customers could initially experience significant rate increases, the government could mitigate these increases through such mechanisms as rate caps. It should also be noted that, after a divestiture, preference customers would pay the same market rates as neighboring utilities who lack access to PMA power.

A divestiture's goals would affect how the government proceeds in divesting its hydropower assets. In addition, trade-offs and the terms and conditions of any divestiture would need to be considered carefully so as not to jeopardize the government's finances. If the government decided to obtain a larger price for its assets, it could choose to retain many of the liabilities and related costs—for example, by retaining the costs of mitigating environmental damages. In contrast, if the government transferred these liabilities and costs, the prices obtained for its assets would likely be less than if it kept these liabilities and costs.

Recommendations

This report contains no recommendations.

Agency Comments

GAO provided a draft of this report to DOE (which represented the views of Southeastern, Southwestern, and Western), the Department of the Interior (including the Bureau), the Department of Defense (including the Corps), Bonneville, and the Federal Energy Regulatory Commission. The comments of DOE, Interior, the Corps, Bonneville, and the Federal Energy Regulatory Commission, and GAO's responses to those comments are included in appendixes VI, VII, VIII, IX, and X, respectively.

In commenting on the report, DOE concurred that in some cases the PMAS do not recover the full costs of marketing federal power as defined by GAO. However, according to DOE, GAO overstates these costs because it overstates the amount of investment that was financed with interest rates that were less than the Treasury's cost of borrowing. GAO does not agree that it overstates these costs. The interest rate used by the PMAs in calculating the amounts to be repaid through their power rates was less than the Treasury's cost of borrowing those funds. Furthermore, GAO believes that by not limiting the estimate of the financing costs to differences in interest rates, GAO's methodology accurately captures the full amount of the financing costs. DOE concurred that some portion of $1.4 billion of federal investment in power-related assets is at risk of not being repaid through PMAS' power rates. However, DOE believes that GAO overstates the amount of investment at risk of not being repaid. GAO believes its assessment of risk is accurate and did not change its assessments because DOE did not provide information that would allow GAO to change its assessments. More detailed responses to DOE's comments are found in appendix VI. DOE also provided general policy comments and technical clarifications that are incorporated in the report as appropriate.

Interior provided general and specific comments on the report. The most significant comment was that the reduced percentage of time the Bureau's plants could generate power was not an indication of inadequate maintenance, but rather caused by the need, under statutes, to manage water projects to satisfy multiple uses, such as irrigation. GAO disagrees that the need to manage water projects for multiple uses necessarily leads to a reduced percentage of time to generate power. GAO notes that the percentage of time a plant can generate electricity is not affected by nonpower uses of water but rather by scheduled and unscheduled repairs of the plants.

Defense presented detailed, technical, and clarifying comments that GAO incorporated into the report as appropriate. For example, Defense provided GAO with recent data regarding the improved performance of the Corps' hydropower plants. It also provided information about $450 million in funding to repair and rehabilitate those plants. GAO incorporated this information into the report.

In commenting on the report, Bonneville stated, most significantly, that its activities do not impose substantial net costs to the federal government. GAO disagrees because Bonneville's operations entailed net financing costs to the government of about $377 million in fiscal year 1996.

The Federal Energy Regulatory Commission provided GAO with technical comments regarding the implementation of the Commission's Order 888 and its applicability to the PMAS. GAO incorporated those comments into the report.

Contents

Related GAO Products

Tables

Figures

Abbreviations

CVP	Central Valley Project
DOE	Department of Energy
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
G&T	generation and transmission
xID	
IOU	investor-owned utility
ISO	independent system operator
kW	kilowatt
kWh	kilowatthour
MW	megawatt
MWh	megawatthour
NRC	Nuclear Regulatory Commission
O&M	operations and maintenance
PMA	power marketing administration
POG	publicly owned generator
REA	Rural Electrification Administration
RUS	Rural Utilities Service

TVA	Tennesee Valley Authority

Introduction

The electricity industry has been predominantly monopolistic and noncompetitive. Utilities (primarily investor-owned utilities—IOU) build power plants and power lines to provide all of the electricity needed by all existing and future customers in their exclusive service areas. Regulators in the states allow utilities to charge electricity rates that give them a regulated, specified level of return on these investments.

IOUS were initially reluctant to provide electricity to rural areas, mostly because the sparse population made it difficult for them to recover their costs and to earn a profit. The federal government has played an important role in the traditional market by selling power to rural America. The Department of the Interior's Bureau of Reclamation (the Bureau) and the Department of the Army's Corps of Engineers (the Corps) generate electricity at hydropower plants located at major federal water projects. The Department of Energy's (DOE) power marketing administrations (PMA) generally sell this power in wholesale markets, mostly to publicly and cooperatively owned utilities that, in turn, sell power to end-use (retail) consumers. The PMAS repay the federal investment in the government's power plants, power lines, and related assets through the revenues they earn by selling power. The Tennessee Valley Authority (TVA), a federal corporation, generates and markets power throughout Tennessee and parts of six other southeastern states. Moreover, the Department of Agriculture's Rural Utilities Service (RUS) makes and guarantees loans to rural utilities to finance the construction and development of electric power systems. Although critics question the federal government's role in providing power or in financing improvements to rural utility systems as markets restructure, the activities continue.

However, the traditional structure of the electricity industry has begun to change. Legislation and new generating technologies have introduced increased competition into the market, changing the environment in which the PMAS must operate successfully if they are to repay the federal investment in the power program.

Structure of the Electric Power Industry

Federal and state agencies regulate the activities of electric utilities. Traditionally, electricity service was viewed as a "natural monopoly": A central source of power was seen as the most efficient way of generating, transmitting, and distributing electricity at a reasonable cost. Under the traditional regulatory compact between electric utilities and their state regulators, electric utilities were guaranteed monopolies within their exclusive service areas and regulated rates of return on their capital investments. In return, these utilities built generating and other facilities to provide all of the electricity needed by all current and future customers in their service areas. Under traditional "cost-of-service" regulation, electricity rates approved by state regulators reflected the utilities' costs of building new generating plants and operating the power system. As shown in table 1.1, IOUs dominate the electricity markets: Although they account for only about 8 percent of the nation's almost 3,200 electric utilities, they have over 75 percent of utility sales to ultimate customers and over 77 percent of total utility power generation. Most IOUs sell power at retail rates to several different classes of consumers and at wholesale rates to other utilities, including other IOUs; federal, state, and local government utilities; public utility districts; and rural electric cooperatives.

The traditional regulatory role of the federal and state governments was established under the Constitution and developed by federal law. Specifically, the Federal Power Act (formerly the Federal Water Power Act), which was enacted in 1920, and the Public Utility Holding Company Act established a regime of regulating electric utilities that gave specific and separate powers to the states and the federal government. State regulatory commissions (generally called "public utility" or "public service commissions") regulate utilities' activities within state boundaries, including the setting of wholesale and retail electric rates. At the federal level, the Securities and Exchange Commission regulates interstate electric utility holding companies by requiring them to register and divest holdings so that each company becomes a single consolidated system serving a specific geographic area. In addition, the Commission regulates how the holding companies issue and acquire securities. Under the Federal Power Act, the Federal Energy Regulatory Commission (FERC), formerly the Federal Power Commission, regulates interstate aspects of the electric utility industry, including financial transactions, wholesale rates, and interconnection and transmission arrangements.

In addition to IOUs, 932 customer-owned rural electric cooperatives and 2,014 publicly owned utilities provided power in 1996. Most rural electric cooperatives, usually formed and owned by residents of rural areas, distribute electricity only to their members. Operating throughout the nation except for Connecticut, Hawaii, and Rhode Island, cooperatives constituted 29 percent of all the nation's electric utilities in 1996. Publicly owned electric utilities are nonprofit state and local government agencies, such as municipal utilities, state authorities, public power districts, and irrigation districts. DOE views publicly owned power as providing competition for IOUs and as charging power rates against which the power rates of IOUs can be compared. In 1996, almost 63 percent of all electric utilities in the nation were publicly owned utilities. Cooperatives and publicly owned utilities buy power from wholesale providers for sale to retail customers. However, some cooperatives and publicly owned utilities also generate their own power and transmit it to other utilities or distribute it to their own retail customers. The generation and share of the national energy supply for these types of utilities are provided in table 1.1.

Table 1.1: Number of Electric Utilities by Class of Ownership in 1996

Type of utility	Number	Percent of total	Net[a] generation	Percent of total	Sales[a]	Percent of total
Investor-owned	243	7.6	2,374.4	77.2	2,346.1	75.7
Cooperatives	932	29.1	139.2	4.5	258.4	8.3
Publicly owned	2,014	63.0	266.1	8.6	450.9	14.5
Federal	10[b]	0.3	297.9	9.7	45.6	1.5
Total	**3,199**	**100.0**	**3,077.4**	**100.0**	**3,101.1**	**100.0**

[a]Net generation and sales are in millions of megawatthours (MWh). One MWh equals 1,000 kilowatthours (kWh). One kWh equals 1,000 watthours. One watthour equals the total amount of electricity used in 1 hour by a device that uses one watt of power for continuous operation. A watt is the basic unit used to measure electric power.

[b]In addition to the five PMAs, the Bureau, the Corps, and TVA, DOE's Energy Information Administration (EIA) classifies the Department of the Interior's Bureau of Indian Affairs and the International Water and Boundary Commission as federal electric utilities.

Source: Developed by GAO from data provided by EIA.

The Role of the Federal Government in Traditional Electricity Markets

The federal government has played a significant role in the development of electricity markets. Because it was too expensive for IOUs to serve rural areas, federal power agencies provided power to those areas. In addition, the government provided financing to rural utilities to assist them in building and maintaining electricity distribution systems that provide electricity to rural users. In 1996, federal utilities provided almost one-tenth of the nation's power. As a result of these activities, the federal agencies that generate and/or market electricity and that make or guarantee loans to finance improvements to rural electric systems had incurred a debt of over $84 billion as of September 30, 1996. This debt, it should be noted, can be classified as direct and indirect. The direct debt, totaling over $53 billion, is owed directly to the federal government—for example, RUS' borrowers owe about $32 billion. The indirect debt, over

$31 billion, is owed by the federal agencies to nonfederal parties—for example, TVA owed about $24 billion to nonfederal bondholders.

Federal Agencies Generate and Market Electricity

Federal entities that generate and/or market electricity—primarily the Bureau, the Corps, the PMAS, and TVA—provided about 10 percent of the nation's electricity supply in 1996.[1] The Bureau and the Corps generate hydropower at about 130 federally owned power plants located at federal water projects. Because these projects are managed for multiple purposes (for example, providing water for irrigation, water supplies, navigation, flood control, and recreation), the amount of power generated and marketed is affected by the availability and use of water for these other purposes.[2]

Power generated by the Bureau and the Corps is marketed by four of DOE's five PMAS: the Bonneville Power Administration (Bonneville), plus the three that are the focus of this report: the Southeastern Power Administration (Southeastern), the Southwestern Power Administration (Southwestern), and the Western Area Power Administration (Western). The fifth PMA, the Alaska Power Administration, differs from the others in that it operates its own power plants and distributes power directly to end-use (retail) customers.[3] The PMAS in 1996[4] provided about 5 percent of the nation's power.

The PMAS' mission is to market federal hydropower at the lowest possible rates that are consistent with sound business practices. The power the PMAS market is the power that remains after it has been consumed for project purposes—for example, to pump water to fields that are being irrigated. By law, the PMAS are to give priority in the sale of power to "preference customers"—public bodies (such as municipal utilities, irrigation districts, military installations, and other federal agencies) and cooperatives. Each PMA has its own specific geographic boundaries, federal water projects from which it markets power, statutory responsibilities, and operation and maintenance responsibilities. Except

[1]The latest year for which the PMAs provided this information at the time we performed our review.

[2]The evolution of the multiple purposes for federal water projects is discussed in Bureau of Reclamation: Reclamation Law and the Allocation of Construction Costs for Federal Water Projects (GAO/T-RCED-97-150, May 6, 1997).

[3]The Alaska Power Administration's projects do not serve multiple purposes the way other federal water projects do. Its projects provide power only. Its power assets are being divested under the Alaska Power Administration Sale and Termination Act, enacted in November 1995. DOE expects final divestiture by August 1998. See Federal Electric Power: Views on the Sale of Alaska Power Administration Hydropower Assets (GAO/RCED-90-93, Feb. 22, 1990).

[4]The latest year for which the PMAs provided this information at the time we performed our review.

for the Alaska Power Administration, the PMAS generally do not own, operate, or control the facilities that generate electric power; the generating facilities are controlled by the operating agencies—most often the Bureau and the Corps. The PMAS, except for Southeastern, do own and operate transmission facilities. Southeastern relies on the transmission services of other utilities to transmit the power it sells to its customers.

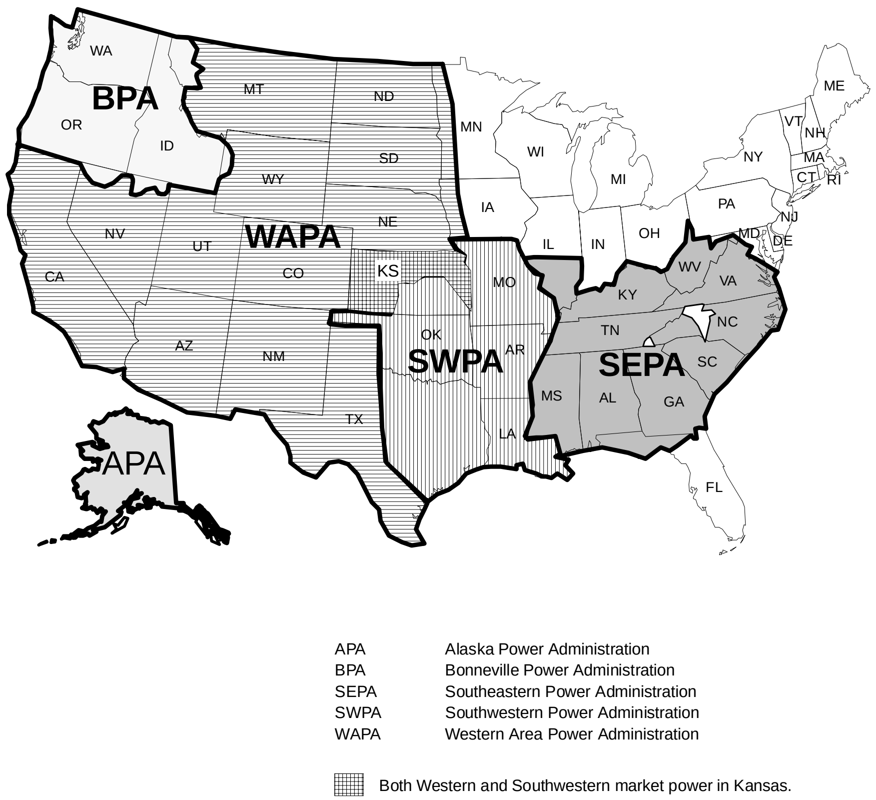
The PMAS are generally required to recover all costs incurred as a result of producing, transmitting, and marketing power, including repayment of the federal investment in the power generating facilities and other debt, with interest. Certain nonpower costs are also allocated to power revenues for repayment. For example, under the concept of aid-to-irrigation, revenues earned from the sale of power repay the federal investment in irrigation facilities that the Secretary of the Interior deems is beyond the ability of irrigators to repay. According to Bureau officials, power revenues are ultimately expected to cover about 70 percent of the federal investment in completed irrigation facilities. As of September 30, 1996, the PMAS and TVA had an outstanding debt of about $52 billion related to financing the construction and operation of power plants, transmission lines, and related electricity assets, as well as other costs that are allocated to be repaid through revenues earned from the sale of electricity. TVA owed about $28 billion; Bonneville owed about $17 billion; and Southeastern, Southwestern, and Western owed the balance—about $7 billion.[5]

Together, DOE's five PMAS and TVA[6] market power within 34 states. They do not serve Hawaii and states in the Northeast and upper Midwest. Figure 1.1 shows the service areas of the PMAS.

[5]See Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses: Volume 1 (GAO/AIMD-97-110, Sept. 19, 1997).

[6]TVA markets power in Tennessee, as well as parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. Southeastern, which sells power to TVA, also markets power within these states, as well as other states in the Southeast.

Figure 1.1: The Service Areas of the PMAs



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

The Congress established the first PMA, Bonneville, by passing the Bonneville Project Act of 1937 to market federal power in the Pacific Northwest. (See app. III for a more detailed discussion of Bonneville.) In 1943, the Secretary of the Interior established Southwestern under the President's war powers. The Flood Control Act of 1944 provided the authority to create PMAs and also gave the Secretary of the Interior jurisdiction over the Corps' electric power sales. The Secretary of the Interior established Southeastern in 1950 and Alaska in 1967. The last PMA, Western, was authorized by the Department of Energy Organization Act of 1977, when the four existing PMAs were transferred from the Department of the Interior to DOE.[7]

[7]The DOE Organization Act transferred power marketing responsibilities and transmission assets that had been previously managed by the Bureau of Reclamation to Western.

The largest individual federal power producer, however, is TVA, which by some measures is the largest utility in the nation. Providing about 5 percent of the nation's power, TVA generates its own power and markets it in wholesale markets, as well as directly to large industrial customers.[8] TVA also approves the retail rates charged by the 159 municipal and cooperative utilities that are its primary customers. In 1933, the Congress created TVA as a multipurpose, independent federal corporation to develop the resources of the economically depressed Tennessee River Valley: TVA was to improve navigation, promote regional agricultural and economic development, and control the flood waters of the Tennessee River. To those ends, TVA erected dams and hydroelectric power facilities on the Tennessee River and its tributaries. Today, the power program is by far TVA's largest activity, with about $5.7 billion in annual operating revenues in fiscal year 1996. TVA's hydroelectric facilities, coal-fired power plants, nuclear generating plants, and other power facilities—with a total generating capacity of over 28,000 megawatts (MW)—provide electricity to nearly 8 million people in Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. (See app. I for a more detailed discussion of TVA.)

The Government Also Makes or Guarantees Loans to Finance the Construction and Operation of Rural Electricity Systems

In addition to authorizing the sale of federal power in rural areas, the Congress passed laws to encourage the development of nonfederal power systems. IOUs were historically reluctant to serve sparsely populated areas because of the heavy capital costs involved in installing power systems and serving relatively few customers. As a result, in 1935, scarcely 1 in 10 farm households in the United States had electricity. The Rural Electrification Act of 1936 authorized the Rural Electrification Administration (now RUS) to provide loans and credit assistance to organizations that generate, transmit, and/or distribute electricity to small rural communities and farms. From fiscal years 1992 through 1996, RUS made or guaranteed 880 loans to rural utilities, some of which buy power from the PMAs. The outstanding balance on RUS' loans and loan guarantees was about $32 billion as of September 30, 1996.[9] (See app. II for a more detailed discussion of RUS.)

[8]TVA sold power to 67 directly served industrial customers and federal agencies in 1996.

[9]The outstanding balance on RUS' loans and loan guarantees was about $31 billion as of June 30, 1997.

New Legislation and Technologies Serve as a Catalyst for Change in Electricity Markets

From 1935 through the mid-1960s, little change occurred in the way utilities satisfied demand for electricity and were regulated. For decades, they were able to meet increasing demand at decreasing prices because they achieved economies of scale through capacity additions and technological advances. During much of this period, demand for electricity grew at a faster rate than the gross national product. However, in 1976, electricity growth did not exceed overall economic growth, and in 1982 electricity consumption declined. These adverse trends for the electric utility industry were caused by such events as (1) the Northeast power blackout of 1965, which raised concerns about reliability; (2) the Arab oil embargoes of the 1970s, which resulted in increases in fossil fuel prices; and (3) the passage of the Clean Air Act of 1970 and its 1977 amendments, which required utilities to reduce pollutant emissions. Because of the decline in the rate of growth in demand for electricity, utilities could no longer assume that prior patterns in demand-growth would continue into the future. How to satisfy the future demand for power became an increasingly uncertain issue.

In addition, since the late 1970s, statutory and technological changes have created a climate for change in traditional electricity markets. In general, electricity markets are starting to evolve from domination by large, monopolistic IOUs to competition among IOUs, nonutility generators, power marketers, and others. In the future, electricity markets may evolve into ones in which electricity is a commodity. In addition, states are taking action to ensure that retail consumers will be able buy power from a variety of competing sources.

Federal Laws Encourage Competition

In 1978, the Public Utility Regulatory Policies Act and the Fuel Use Act encouraged the growth of a nonutility sector of the electricity business. These laws were passed to lessen the nation's dependence on foreign oil and encourage alternative sources of power. The Public Utility Regulatory Policies Act required commercial utilities to buy power from nonutility generators, called "qualifying facilities." These entities had to meet certain criteria specified by FERC for such matters as their ownership and operating efficiency. In addition, the act introduced the pricing of electricity on a competitive basis: As more nonutility generators entered the market, FERC began approving certain wholesale transactions that had rates that resulted from a competitive bidding process. Many of the qualifying facilities generated power in nontraditional ways—for instance, by using small hydropower plants, cogeneration,[10] or renewable sources. Under the Fuel Use Act, electric utilities could not use natural gas to fuel new generating technology; however, these "qualifying facilities" could. They were able to take advantage of new generating technologies, such as combined-cycle gas turbine generation[11] that can be built with less capital than larger power plants. Although the Fuel Use Act was repealed in 1987, qualifying facilities and small power producers had already gained a portion of the total electricity supply. For instance, according to the association of IOUs, in 1995 nonutility generators built about 60 percent of the nation's new electric generating capacity.

The Energy Policy Act of 1992 was perhaps the most significant legislative catalyst for increased competition. It expanded nonutility markets by creating a new category of power producers—"exempt wholesale generators." Like qualifying facilities, exempt wholesale generators do not sell their power in retail markets and own only very limited transmission facilities. Although FERC does not regulate exempt wholesale generators under the Public Utility Regulatory Policies Act, it regulates most of them as public utilities under the Federal Power Act. Under FERC's regulations, exempt wholesale generators may charge market-based rates if they and their affiliates lack market power. Unlike the requirement under the Public Utility Regulatory Policies Act that utilities purchase power sold by qualifying facilities, there is no federal mandate that utilities buy exempt wholesale generators' power. The Energy Policy Act also allows FERC, upon application, to order wholesale wheeling[12] of electricity if such an order does not, among other things, unreasonably impair reliability. It is now possible for a municipal utility that is served by an IOU to seek cheaper power from a neighboring utility. The Energy Policy Act also authorized FERC to set transmission rates at levels that permit the utilities to recover all of the costs incurred in providing transmission services, including legitimate, verifiable, and economic costs.

In April 1996, pursuant to its authorities under the Federal Power Act, FERC issued a ruling on transmission access. Order 888 requires public utilities that own, control, or operate facilities that transmit electricity in interstate

[10]Cogenerators sequentially or simultaneously produce electric energy and another form of energy (such as heat or steam) using the same fuel source.

[11]Combined cycle gas turbines use waste heat boilers to capture exhaust energy from steam generation.

[12]To "wheel" is to use the transmission facilities of one system to transmit power and energy by agreement of, and for, another system for a charge. Wholesale wheeling usually refers to transmission service to utilities that resell power to end users; retail wheeling refers to transmission service to end users. The act specifically prohibited FERC, however, from ordering retail wheeling directly to an ultimate consumer.

commerce to offer both point-to-point and network transmission services under terms and conditions that are comparable to those that they provide for themselves.[13] Public utilities must offer those services through open-access, nondiscriminatory transmission tariffs[14] containing minimum terms and conditions.[15] In addition, Order 888 allows utilities the opportunity to seek recovery of certain stranded costs[16] from those customers wishing to leave their current supply arrangements. However, according to the Deputy Director, FERC's Office of Electric Power Regulation, the open-access provisions of Order 888 do not apply to the PMAS, among other entities. Therefore, FERC cannot order the PMAS to provide open transmission services on a general basis. Operating under its authority under the Federal Power Act, FERC can order the PMAS to provide transmission only on a case-by-case basis. However, to facilitate a unified national approach to open-access transmission, DOE directed its PMAS that have transmission facilities to publish generally applicable open-access transmission tariffs, including ancillary services, in a manner comparable to the service tariffs and other measures required of transmission owners and operators that are regulated under FERC's final rule. In December 1997, Southwestern and Western filed open-access transmission service tariffs with FERC, pursuant to Order 888. The tariffs are to govern future access to available electric transmission and, according to DOE, are consistent with the tariffs of other wholesale transmission providers. Bonneville had filed its tariffs earlier.

Utilities Respond to Increased Competition

In response to the uncertainties about how the electricity market will change and how fast, utilities have begun to implement new strategies to compete. Some are acquiring other utilities or merging with them. After

[13]For purposes of Order 888, FERC has the authority to order open transmission access on a generalized basis to "public utilities"—IOUs and electric cooperatives with transmission assets that do not have loans from RUS, among others. FERC's order does not apply to publicly owned utilities (e.g., municipal utilities and public utility districts), TVA, or the PMAs.

[14]A tariff sets forth rates, terms, and conditions of transmission service.

[15]A second FERC rule, Order 889, known as the Open Access Same-Time Information System rule, requires public utilities to establish electronic systems to share information about available transmission capacity. The order also requires utilities to separate their wholesale power marketing and transmission operation functions but does not require corporate unbundling or divestiture of assets.

[16]Stranded costs are investments or assets owned by regulated utilities that are not likely to be competitive in a restructured marketplace. More specifically, FERC defines wholesale stranded costs as any legitimate, prudent, and verifiable cost incurred by a utility to provide service to a wholesale requirements customer or a newly created wholesale power sales customer that subsequently becomes, in whole or in part, an unbundled wholesale transmission service customer of such utility. Order 888 allows utilities to seek recovery of wholesale stranded costs associated with wholesale power requirements contracts executed on or before July 11, 1994.

years of virtually no mergers, many mergers have been completed or proposed since the Energy Policy Act was enacted in October 1992. For example, for IOUs alone, from October 1992 to January 1998, over 40 mergers had been proposed and 17 had been completed, according to the Edison Electric Institute—the national trade association for IOUs. Utilities are also restructuring themselves and decreasing their operating costs through reorganizations and layoffs. Some utilities are changing how they plan to satisfy future demand for electricity and changing the types of resources they acquire. Because of uncertainty about market conditions, instead of continuing to plan to meet long-term load forecasts, utilities are focusing more on meeting more immediate demand for power. Thus, utilities are now tending to buy resources that are flexible and allow them to adapt quickly to changing market conditions, such as smaller natural gas-fired power plants and purchased power. Utilities are also retiring power plants if they believe those plants may become uneconomic after the industry is restructured.

In responding to competitive challenges, utilities are trying to compete for the business of other utilities' wholesale customers and defending their business with existing customers. For example, as cited in our 1995 TVA report, Virginia Power cut one wholesale customer's rates by 5 percent to fend off the marketing efforts of a neighboring utility.[17]

Federal power suppliers have also taken actions to become more competitive. For example, after the departure of half of its industrial load, TVA froze its rates from 1986 through 1997, although a rate increase was approved for 1998. Moreover, Western recently announced a decrease of over 20 percent, effective October 1, 1997, in the composite rates of power it markets from hydropower plants in the Central Valley Project in California. In addition, according to DOE's Power Marketing Liaison Office, Western began a process in fiscal year 1995 to restructure itself. The goals of this program included reducing federal and contractor staff from fiscal year 1994 levels by 24 percent, saving $25 million in costs annually, and reducing Western's organizational units. For its part, Southwestern has adopted a program to reduce overhead costs by reducing targeted administrative positions, reducing the number of managers and supervisors, and eliminating one field office.

[17]Tennessee Valley Authority: Financial Problems Raise Questions About Long-term Viability (GAO/AIMD/RCED-95-134, Aug. 17, 1995).

Several Factors Will Affect How Fast Competitive Markets Emerge

Electricity markets are not yet fully competitive but are moving in that direction. Although markets for wholesale transactions are becoming competitive, retail markets are still uncompetitive. Supporters of restructuring argue that markets will not be truly competitive until both wholesale and retail markets are transformed. In addition, other issues that need to be resolved include deciding (1) how stranded costs are to be recovered, (2) how electricity is to be transmitted in competitive markets, (3) how electricity is priced in these markets, and (4) how consumers at the retail level are to be offered a choice of power suppliers. Once restructuring is complete, retail electricity rates may fall between 6 percent to 19 percent by the year 2015, depending on the intensity of competition, among other factors, according to DOE's EIA.

Recovery of Stranded Costs

Arguably the most significant issue that policymakers will face is how to recover the stranded costs associated mainly with building large baseload power plants and other assets under the old regulatory regimen. IOUs erected large amounts of nuclear generating capacity and entered into long-term purchased power contracts to serve existing and future loads. Under the traditional covenants between IOUs and their regulators, the capital and operating costs associated with those assets were recovered through rates. Now, with power generation costs dropping and prospects that competition will affect market prices, these high-cost plants are becoming uneconomical and the costs associated with them may be "stranded." Estimates of the investment in such assets nationwide range from $10 billion to $500 billion.[18]

The issue of how to recover stranded costs—that is, who should pay—is being debated. In addressing the recovery of stranded costs in the context of retail competition, some states have proposed "sharing the pain": Utilities could recover or offset the stranded costs by taking mitigating actions (for example, by implementing accelerated depreciation of generating assets, writing off the book value of stranded assets, adjusting dividends to investors, or decreasing operating expenses); ratepayers could pay through rate increases that regulators hope will be temporary; or bonds could be sold to the public to pay off the stranded costs and to

[18]For example, see EIA's Electricity Prices in a Competitive Environment: Marginal Cost Pricing of Generation Services and Financial Status of Electric Utilities—A Preliminary Analysis Through 2015 (DOE/EIA-0614, Aug. 1997). EIA estimates that if regulatory means are not found to mitigate stranded costs, then the reduction in market value for existing generating assets could range from $72 billion to $169 billion (1995 dollars), under moderate competition scenarios. If competition is "intense," the reduction in value may be as great as $408 billion. These reductions may be about $30 billion to $40 billion less over a 2-year period, during which electricity markets phase in retail competition, because regulated rates would continue to contain the stranded costs.

avoid rate increases. However, some consumer groups believe that since utilities incurred the costs, they should bear the burden of repayment. For example, an attempt to securitize the costs of a nuclear power plant failed in Connecticut's legislature because opponents, including consumer groups, believed the issuance of bonds amounted to a "bailout" of the utility. Staffs of state public utility commissions have argued that because IOUS incurred stranded costs under the old regulatory compact, IOUS should be allowed to recover at least some of these costs before they must charge market prices for power. How stranded costs are divided between utilities and their ratepayers, the period of time allowed for their recovery, and how much the recovery of stranded costs affects rates will determine when retail markets become competitive and to what degree.

Transmitting Power in Competitive Markets

To promote competition, new methods must be found to transmit power. Under current transmission arrangements, wholesale customers frequently do not find it economical to buy power from a distant utility because it must be transmitted over the power lines of intervening utilities, each of which adds a transmission or wheeling tariff to the price of the power. For example, in 1995 during our review of the financial viability of TVA,[19] we found that although an IOU in the Southeast offered power that was competitively priced, transmitting it to TVA's customers through one intervening utility might increase the price by about 10 percent, rendering its delivered price uncompetitive. In addition, according to DOE officials, some of the power transmitted is lost over distances.

To facilitate competitive transmission of power, many state regulators and FERC are advocating the establishment of "independent system operators" (ISO). Utilities in a given geographic area would transfer the operation of their transmission assets to an independent party that would transmit electricity reliably, safely, and efficiently in a nondiscriminatory fashion. For example, California has established an Independent System Operation Restructuring Trust to award funding to parties that will assist in establishing an ISO to begin providing service in 1998. The PMAS are also participating in the formation of ISOS. For example, Western is negotiating with other utilities in the Southwest to establish the Desert Southwest Transmission and Reliability Operator (an ISO) as well as to participate in the California ISO. Concerns exist that such arrangements may be problematic from legal and constitutional viewpoints. According to Western officials, however, in Western's agreements with other utilities pertaining to the ISO, Western is taking care to ensure that its obligations

[19] GAO/AIMD/RCED-95-134.

under federal law and its contractual agreements with preference customers are protected. For example, Western officials believe that, under language provided by the PMA and accepted by FERC on Western's participation in the California ISO, nothing in the ISO's tariff shall compel any person or federal entity to violate federal statutes or regulations or compel any federal agency to exceed its statutory authority as defined in applicable federal statutes, regulations, or orders lawfully promulgated thereunder. These provisions also state that if any provision of the tariff requires any person or federal entity to give an indemnity or impose a sanction that is unenforceable against a federal entity, the ISO shall submit to the Secretary of Energy or DOE official a report of the situation. The Secretary or other official will take the steps necessary to remedy the situation to the extent possible.

Pricing Power in Competitive Markets

State public utility commissions are also taking steps to facilitate competitive pricing of power. They have supported establishing power pools or exchanges. Under these arrangements, members buy and sell power through the pool or exchange it at a price that reflects market demand and that promotes competition between utilities and other suppliers. For example, under one method, generating companies could bid to sell their power to the pool. The pool would then establish hourly or spot prices based on these bids. In California, the power pool will publish prices every hour or half hour, to be viewed by electric customers, investors, and power marketers. With these visible price signals, wholesale and retail buyers will be able to make efficient purchasing decisions and adjust their consumption of power from peak to off-peak periods when prices drop.

Promoting Retail Competition

As of February 1998, all 50 states and the District of Columbia had considered reforming their respective retail markets, according to the National Regulatory Research Institute[20] and records obtained from state regulatory agencies. At that time, at least 17 states had actually implemented plans to restructure the industry by enacting restructuring legislation or by adopting final orders.[21] Regulators in these states hope

[20]The National Regulatory Research Institute was established by the National Association of Regulatory Utility Commissioners to provide research, educational, and technical services to the state regulatory commissions.

[21]The 10 states that had enacted legislation to restructure their retail markets were California, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, and Rhode Island. Seven states that had adopted final orders without enacting legislation were Arizona, Maryland, Michigan, New Jersey, New York, Texas and Vermont.

that industrial, commercial, and ultimately residential consumers will be able to choose their power supplier, rather than being tied to one utility. These states hope to establish retail choice at all levels by 1998 at the earliest and 2005 at the latest. Supporters of retail competition hope that it will nearly complete the restructuring process for electricity markets and foster competitive pricing throughout the nation.

At the time we completed our review, states such as Montana, New Hampshire, and New York had asked utilities to implement pilot retail choice programs so that broad issues that could affect widespread competition later could be identified. Several states, such as Michigan, Pennsylvania, and Rhode Island, were implementing retail competition in phases—for instance, extending it first to industrial and commercial customers and then to residential customers. As mentioned previously, some states were addressing the issue of stranded cost recovery. In addition, at least 8 of these 17 states were also encouraging utilities to continue their "social" programs—such as energy efficiency and conservation programs, use of renewable sources of power, and low-income energy assistance programs. These programs can be funded by charging consumers a nonbypassable fee or by instituting a tax or surcharge on all energy services. Also, to foster competition and decrease utilities' market power, public utility commissions were requiring utilities to "unbundle" their services—that is, to divest themselves of, or otherwise transfer, the generation, transmission, and distribution of power.

When restructuring is completed, states expect that retail customers will enjoy a variety of options for taking advantage of retail competition. For instance, the California Public Utility Commission expects that customers will use metered information about how much power they are using at specific times of day and how much that power costs. They could then decide which supplier to buy from during specific times to minimize costs. They may be able to negotiate directly with a supplier or use the services of an energy marketer or broker. In Maine, it is envisioned that consumers that are unwilling to shop for alternative suppliers will be able to adopt the "standard service option" from their existing utility. The existing utility will use a competitive bidding process in order to buy power for its ratepayers at prices that are comparable to today's prices. Other options envisioned for Maine's ratepayers include signing contracts with power marketers or aggregators that are short term, thus enabling them to buy power at a low price but with a risk of rate hikes or rate instability. They will also be able to buy power under longer term contracts at more expensive but more stable rates. Ratepayers will also be able to purchase "green power" (i.e., power from nonpolluting sources such as renewable sources).

Some states, however, are urging a cautious approach to retail restructuring. For example, the staff of Virginia's public utility commission in an October 1996 report states:

> "Those states that are aggressively pursuing competitive restructuring are invariably high-cost states with little to lose. On the other hand, as a lower-cost state, Virginia may have little to gain and much to lose by being on the leading. . .edge of this restructuring movement. We should also take note of the slow pace of those mostly low-cost states surrounding Virginia—North Carolina, Tennessee, Kentucky, West Virginia, and Maryland. Consequently, Virginia should pursue a cautious and measured approach to adopting competitive initiatives, fully exploiting non-painful learning opportunities through observing the successes and failures of retail experiments and restructuring efforts in the more aggressive states."[22]

Furthermore, in Nebraska, a state where all electric power is provided by public entities and where power rates are among the nation's lowest, the state's largest electric utility has asked a federal appeals court to overturn FERC Orders 888 and 889. The utility challenged the orders on the grounds that FERC does not have the legal authority to impose on the utility the same regulatory regime that it imposes on private investor-owned electric utilities because the utility is a political subdivision of the state of Nebraska.

Objectives, Scope, and Methodology

Federal agencies that generate or market electricity and that make or guarantee loans to finance improvements to rural power systems incurred a debt of about $84 billion[23] as of September 30, 1996.[24] Three agencies that market federal electricity—the Southeastern, Southwestern, and Western—are responsible for $7 billion of this debt. They face an uncertain future as electricity markets become increasingly competitive. In response, the Chairmen of the House Committee on Resources and the Subcommittee on Water and Power asked GAO to focus on these three PMAS and to (1) examine whether the government operates them and the related electric power assets in a businesslike manner that recovers the federal government's capital investment in those assets and the costs of operating

[22] Staff Investigation on the Restructuring of the Electric Industry, Virginia State Corporation Commission (Oct. 1996).

[23] Dollar figures are in constant 1996 dollars, unless otherwise specified.

[24] GAO/AIMD-97-110.

and maintaining them and (2) identify options that the Congress and other policymakers can pursue to address concerns about the role of these three PMAS in restructuring markets or to manage them in a more businesslike fashion. GAO's options also apply to the Corps and the Bureau, which generate most of the power these PMAS market. Although GAO's options apply only to these agencies, the report also provides information about TVA, RUS, and Bonneville in appendixes I, II, and III, respectively.

We also included in this report information from generalized reports on how federal agencies can be operated in a more businesslike fashion. See Related GAO Products at the end of this report for a list of the products used to prepare this report.

We conducted our review from April 1997 through February 1998 in accordance with generally accepted government auditing standards. Appendix IV contains a detailed description of our objectives, scope, and methodology.

We provided a draft of this report to DOE's Power Marketing Liaison Office that represented the views of Southeastern, Southwestern, and Western; the Department of the Interior (including the Bureau); the Department of Defense (including the Corps); Bonneville; and FERC. Their comments and our responses are included in appendixes VI, VII, VIII, IX, and X, respectively.

The Federal Power Program Operates at a Net Cost, Has Generating Assets That Need Repair, and Presents Some Risk That the Federal Investment May Not Be Recovered

Federal laws and regulations generally require that the PMAs recover the full costs of producing and marketing federal hydropower. The PMAS generally follow these laws and regulations; however, in some cases federal statutes and DOE's rules also prohibit or are ambiguous about the recovery of certain costs. As we reported in September 1997, for fiscal years 1992 through 1996, as a result of its involvment in the electricity-related activities of Southeastern, Southwestern, and Western (the three PMAS), the federal government incurred "net costs" of $1.5 billion[1]—the amount by which the full costs of providing electric power exceeded the revenues from the sale of power. In addition, the availability of many federal power plants to generate electricity is below that of nonfederal plants because, among other factors, the federal plants are aging and because the federal planning and budgeting practices, including those used by the Bureau and the Corps, do not always ensure that funds are available so that repairs can be made when they are needed.[2] The resulting declines in performance decrease the marketability of federal power. The net cost to the Treasury and the performance problems of the federal power plants—when combined with competitive pressures on electricity suppliers to decrease their rates at a time when some federal hydropower project's environmental costs need to be recouped by the PMAS—create varying degrees of risk that some of the federal investment at certain federal generation and transmission projects and rate-setting systems will not be repaid.[3] For example, although the recovery of most of the federal investment in the three PMAS' hydropower-related facilities is relatively secure, up to $1.4 billion of the federal investment for projects or rate-setting systems pertaining to these PMAS, out of a total federal investment of about $7.2 billion, is at some risk of nonrecovery.

[1]Dollars for the net costs are constant 1996 dollars, unless otherwise specified..

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

[3]A rate-setting system is a collection of one of more power projects for which the PMAs set rates.

The Federal Program Does Not Recover All of the Costs of Generating, Transmitting, and Marketing Power

As noted in two of our recent products, the revenues of the government's power generating and marketing activities are not recovering all of the costs associated with the program.[4] These activities operate at a net cost (loss) to the U.S. Treasury.[5] For the three PMAs that are the focus of this report, net costs of $1.5 billion were incurred for fiscal years 1992 through 1996.[6] These net costs fall into several categories: (1) net financing costs, (2) unrecovered employee benefits, (3) unrecovered construction costs, and (4) other costs.

Net Financing Costs of the Three PMAs

We estimate that the net financing costs for the three PMAs' appropriated debt[7] in fiscal years 1992 through 1996 was about $1.2 billion, including $208 million in fiscal year 1996. These costs stem primarily from appropriated debt provided by the federal government at low interest rates with favorable repayment terms. Appropriated debt carries a fixed interest rate and cannot currently be refinanced. Also, the Treasury cannot require the PMAs to repay the debt before it matures. The interest the PMAs pay on their outstanding appropriated debt is often substantially below the rate the Treasury incurred to provide funding to the PMAs. The PMAs' average interest rate on outstanding debt was 3.5 percent,[8] whereas the Treasury's weighted average interest rate on outstanding bonds was 9 percent[9] to provide funding to the PMAs. The PMAs have incurred substantial amounts of appropriated debt at low interest rates primarily because, in accordance

[4]Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, Sept. 19, 1996) and GAO/AIMD-97-110.

[5]The government's power generating and marketing activities are conducted by the Bureau, the Corps, Bonneville, the three PMAs, and TVA. The total net cost of these activities was about $3.6 billion for fiscal years 1992 through 1996. Bonneville's net costs were about $2.1 billion—stemming from a net financing cost to the Treasury of about $2 billion and unrecovered employee benefits of about $110 million. Moreover, TVA had net costs of about $4 million because of unrecovered employee benefits. (See apps. I and III.) Our totals exclude costs related to the Alaska Power Administration, which is to be sold. In addition to the $3.6 billion, the activities of RUS in lending or guaranteeing loans to rural utilities incurred a net cost of $4.9 billion during these years.

[6]Dollars for the net costs are in constant 1996 dollars, unless otherwise specified.

[7]We use the term "appropriated debt" because the PMAs are required to repay appropriations used for capital investments, with interest. However, the Treasury does not technically consider these reimbursable appropriations to be lending.

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

[9]This rate is the weighted average interest rate on the Treasury's entire outstanding bond portfolio (10- to 30-year maturities). We used this interest rate because it reflects Treasury's average interest rate on outstanding long-term debt and most closely matches the terms of the PMAs' appropriated debt.

with the appropriate DOE order,[10] they repay high-interest debt first, and because the appropriated debt they incurred before 1983 was generally at the below-market interest rates in effect at the time.[11]

PMAs' Rates Do Not Recover All Employee Benefit Costs

For current PMA and operating agency employees, the federal government incurs a portion of the cost for Civil Service Retirement System pensions and almost all of the cost for postretirement health benefits. For fiscal years 1992 through 1996, we estimate that the net cost to the federal government of providing these benefits was about $82 million for the three PMAS, including $16 million in fiscal year 1996. The PMAS plan to begin recovering the full annual cost of pension and postretirement health benefits in fiscal year 1998.[12]

PMAs' Rates Do Not Recover All Construction Costs

We found that the three PMAS had incurred costs or had costs allocated to them by the operating agencies for which full costs were not being recovered through the PMAS' rates. These costs were for the few projects that were not yet completed, were under construction, or were canceled. In some cases, this situation occurred because the power generating projects had never operated as designed. In accordance with DOE's guidance, the PMAS set rates that exclude the costs of nonoperational parts of the power projects, including capitalized interest. For example, at the Corps' Russell Project (located on the Savannah River, which serves as the border between Georgia and South Carolina), partially on line since 1985, litigation over large fish kills has kept four of the eight turbines from becoming operational. As a result, over half of the project's construction costs—about $500 million—have been excluded from Southeastern's rates. The net costs of these construction projects for fiscal year 1996 represent capitalized or unpaid interest incurred in that year. For construction projects designed to generate power marketed by the three PMAS, we estimate that for fiscal years 1992 through 1996, the cumulative net costs are $138 million, including $30 million in 1996. The PMAS believe that in most instances, including the Russell project, these net costs will be recovered in future years.

[10]DOE Order RA 6120.2, "Power Marketing Administration Financial Reporting," generally requires the PMAs to repay the highest interest rate debt first, while complying with the repayment periods and unless otherwise indicated by legislation.

[11]In 1983, DOE required that, absent specific legislation to the contrary, appropriations for capital expenditures made after September 30, 1983, would be financed at interest rates equal to the average yield during the preceding fiscal year on interest-bearing securities of the United States, which, at the time the computation was made, have terms of 15 years or more remaining before maturity.

[12]Consistent with current policies and laws, the PMAs do not plan to recover pre-1998 costs.

PMAs' Rates Do Not Recover Some Other Costs

The three PMAs also incurred other net costs that totaled $157 million for fiscal years 1992 through 1996, for such purposes as environmental mitigation and irrigation. In an example involving environmental mitigation, at the Central Valley Project's Shasta Dam in California, the 1991 Energy and Water Development Appropriations Act specified that any increases in Western's costs to purchase power because of bypass releases to preserve fisheries downstream should not be allocated to power; instead, they were paid for by appropriated funding. These costs totaled about $15.3 million in fiscal year 1996 and about $53.8 million for fiscal years 1992 through 1996.[13] In another example of net costs related to irrigation, in May 1996 we estimated that about $454 million in (1) the federal investment in hydropower facilities allocated to irrigation at the Bureau's Pick-Sloan Missouri Basin Program[14] and (2) a portion of the costs associated with storing water for these projects were not likely to be recovered without congressional action.[15] The principal of $454 million had grown to $464 million as of September 30, 1996. As, by law, interest on this amount is not being paid, we estimated that about $70.6 million in interest was unpaid for fiscal years 1992 through 1996.

The Federal Hydropower Assets Need Repair

The availability of federal power plants to generate power is below that of other power plants. Many federal plants are aging (the Bureau's plants average about 50 years in service and the Corps' about 30 years), which increases the need for repairs. At the same time, the Bureau's and the Corps' planning and budgeting processes do not always provide funding to repair the federal power assets when the funding is needed, causing some repairs to be delayed and the power plants to become less available to provide power.

According to the representatives of the PMAs' power customers and our previous work, the maintenance needs of the Bureau's and the Corps' hydropower plants are often underfunded or maintenance is delayed. Furthermore, data from both operating agencies show that their power

[13]According to DOE's Power Marketing Liaison Office, the costs incurred by Western for Shasta bypasses totaled only $1.9 million in fiscal year 1997. Also, as of September 30, 1997, all future purchased power costs incurred by Western due to cold water releases at the Shasta Dam will be reimbursable or included in the power rates for repayment purposes.

[14]The Program consists of 13 of the Corps' and the Bureau's hydropower plants and associated irrigation projects, among other assets, located in the northern basin of the Missouri River. Western sets rates that are designed to recover, not only the federal capital investment in the power system, but also part of the federal investment in irrigation, as well as other costs.

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

plants are generally less available to generate power than power plants operated by other generators of electricity. For example, according to the Bureau's 1996 benchmarking study, while the agency's power plants exceeded the performance of the industry in terms of wholesale firm rate, production costs/kWh, and the number of full-time operation and maintenance employees per generating unit, they lagged behind other nonfederal and federal hydropower producers in availability, forced outage, and scheduled outage factors.[16] However, the availability of the Bureau's hydropower plants over the last 3 years has been above the average availability of the last 15 years. In our 1996 testimony,[17] we reported that in the Corps' South Atlantic Division, the availability of hydropower plants declined from about 95 percent in 1987 to 87 percent in 1995. In addition, the 1995 availability of the Corps' units is below the industry average (89 percent availability) in the Bureau's benchmarking study. Several hydropower plants have been off line for several years because of forced outages.[18] However, DOE's Power Marketing Liaison Office notes that maintenance problems differ by region, district, or division within the operating agencies and that problems in one area should not be extrapolated to all areas.

The planning and budgeting processes that federal agencies—including the Bureau and the Corps—use are not conducive to predictable planning and funding of needed repairs. Pursuant to key laws, including the Antideficiency Act, the Adequacy of Appropriations Act, and the Budget Enforcement Act, federal agencies cannot enter into obligations prior to an appropriation and cannot exceed appropriations unless they have specific statutory authority to do so. Thus, they cannot enter into contracts that obligate them to pay for goods or services unless sufficient funds are available to cover the costs in full. Therefore, agencies must budget for the full costs of contracts up front. Agencies cannot enter into a contract unless it is authorized by law and an appropriation covers the contract's cost. Moreover, fixed spending limits, or caps, apply to all discretionary spending through 1998, including spending for capital items. As we reported in 1996, agency officials often pointed to the poor

[16]Bureau of Reclamation, "Future Generations: A New Era of Power, Performance, and Progress," 1996. According to this document, the Bureau's plants were available about 83 percent of the time in 1994, compared with an industry average of 89 percent.

[17]GAO/T-RCED-96-180.

[18]According to data provided the Corps, agencywide its hydropower plants were available to provide power 92.9 percent of the time in fiscal year 1987 but only 87.9 percent of the time in fiscal year 1995. However, the availability of these plants improved to 88.4 percent in fiscal year 1996 and 89 percent in fiscal year 1997. Also, the percentage of the Corps' plants that experienced forced outages decreased from 5.98 percent in fiscal year 1995 to 4.44 percent in fiscal year 1997. The Corps attributes these improvements, in part, to its program to spend $450 million on repairing its hydropower assets from fiscal years 1993 to 2007.

condition of federal power plants as evidence of a need for more capital spending and reformed budgeting.[19] Some observers add that increased capital spending is needed to generate operational savings in the future. They believe that in an era of constrained federal budgets, spending on capital projects is limited because it entails heavy initial costs and the budget "scoring" for such projects occurs in a single year, while the benefits of it extend for many years.

PMAS and their customers stated that they view the federal planning and budgeting processes as not being well adapted to a commercial activity, such as operating a power system. Under current planning and budgeting systems, the project and field locations of the Bureau and the Corps identify, estimate the costs of, and develop their budget proposals, not only for hydropower but also for such facilities as dams, irrigation systems, and recreational facilities. Hydropower repairs may be assigned lower priorities than other items. Budget requests also have been subject to 10-percent to 15-percent reduction targets at the operating agencies. Under these conditions, the operating agencies, the PMAS, and the PMAS' hydropower customers believe that funding for needed repairs is at best uncertain and at times is unavailable when needed. To ensure that the funding of hydropower maintenance and repair activity receives the funding priority they believe it deserves, customer groups are encouraging the operating agencies to consult them about budgeting and planning for operation and maintenance. Customer groups are also encouraging the federal agencies to seek alternative funding. In most cases, the customers are willing to provide up-front financing for repairs if they are granted more input to planning and budgeting decisions, according to DOE's Power Marketing Liaison Office.[20]

Risk of Nonrecovery of Some Federal Investment Exists

In our September 1997 report, we found that the risk exists that some portion of the government's investment in its power generation and sales program may not be recovered.[21] The total amount of investment in the assets of the power generating and marketing programs of the operating agencies, the three PMAS, Bonneville, and TVA was about $52 billion. This risk stems from several factors, two of which have been addressed already in this report. First, the large net costs of the federal hydropower program

[19]Budget Issues: Budgeting for Federal Capital (GAO/AIMD-97-5, Nov. 12, 1996).

[20]These customers acknowledge that although they can advise the Bureau, the Corps, and the PMAs about capital improvements to be undertaken and the levels of funding needed, the federal agencies retain the ultimate decision-making authority and continue to own the facilities.

[21]GAO/AIMD-97-110.

will continue if action is not taken to recover all of the costs of operating the program. Second, the degraded availability of the generating assets contributes to this risk of nonrecovery because it decreases the marketability of federal power. Other factors also add to the risk of nonrecovery. One factor is that the onset of market competition puts pressure on suppliers to keep their electric rates low or to decrease them. At the same time, the PMAs are being pressured to raise some rates because of the costs at certain projects for mitigating the damage to fish and wildlife habitat from hydropower generation. Moreover, when the operating agencies have had to curtail power generation at particular projects to protect the environment, the PMAs have had to purchase power to fulfill their contracts—another factor that puts upward pressure on the PMAs' rates.

Trend Toward Lower Market Rates Creates Some Risk of Nonrecovery of the Federal Investment

Nationwide electricity rates have dropped over 25 percent after inflation since 1982. According to DOE's Energy Information Administration, retail rates fell from a nationwide average of 8.7 cents per kWh in 1982 to 6.3 cents in 1996 (constant 1992 dollars). This decrease has been caused by factors that include declining fuel prices, an increasing number of fully depreciated power plants, more efficient power generation, and competition from nonutility generators. According to various industry analysts, the restructuring of electricity markets will cause market rates to continue to decline. In addition, according to the Energy Information Administration, retail rates nationwide in 2014 may be about 6 percent to 19 percent below the levels they would have been if competition had not begun. In some cases, wholesale power is available today at about 2 cents per kWh. For example, according to the customer group of the Colorado River Storage Project, in May 1997 one Western customer signed a 20-year contract with an IOU to purchase firm power at a rate not to exceed 1.8 cents per kWh. In contrast, Western's composite rate for power from the project was about 2 cents per kWh. If the PMAs' customers can buy less expensive power from sources other than the PMA, the fixed costs associated with the federal government's power assets will need to be recovered from a decreasing number of customers, placing increased pressure on the PMA to increase its rates. This pressure, in turn, will encourage additional customers to seek power from other sources.

Environmental Mitigation Costs Also Add to the Risk of Nonrecovery

At the same time that wholesale and retail rates are declining, the PMAs are being pressed to raise rates at some projects, primarily because of the need to address concerns about damages to the environment and endangered species. As a result, the three PMAs' hydropower programs have lost revenues, have had to buy more costly replacement power to fulfill their contacts with their power customers, and in some cases have had to spend millions of dollars to mitigate environmental effects. For example, according to DOE's Power Marketing Liaison Office, about one-third of the 1,356 MW capacity at the Bureau's Glen Canyon Dam in Arizona, whose power is marketed by Western, could be lost because power generation has been restricted to protect recreational resources and endangered fish species. The Bureau estimates that Western has lost more than $100 million in revenues. At the same time, Western's costs to buy power to replace the lost generating capacity have averaged about $44 million per year.[22] Furthermore, at the Bureau's Shasta power plant, in California, whose power Western also markets, restrictions on the turbine operations and cold water bypasses to protect the winter run of the chinook salmon resulted in about $50 million in additional costs to purchase power for Western since 1987.[23] Moreover, the shutdown of some units at the Corps' Russell project because of litigation over fish kills resulted in Southeastern's losing $36.1 million in revenues per year since fiscal year 1994.

Up to $1.4 Billion of Federal Investment in the Power Assets of the Three PMAs Is at Risk of Nonrecovery

As we recently reported, some portion of up to about $1.4 billion in federal investment is at varying degrees of risk of not being recovered through power revenues at three generation projects, one transmission project, and two rate-setting systems pertaining to the three PMAs. As of September 30, 1996, the three PMAs had accumulated over $7.2 billion in debt for constructing and upgrading the Bureau's and Corps' generating facilities whose power the three PMAs market, the PMAs' transmission facilities, and the Bureau's irrigation facilities, which are largely repaid with power revenues.[24] In general, the recovery of most of this investment is seen as relatively secure because the three PMAs are generally competitively sound: Their cost to generate power, measured in terms of average revenue per kWh, was 40 percent or more below nonfederal utilities for 1995. However, at some projects, congressional action will be needed to ensure that large amounts of federal investment are recovered. For example, at the Pick-Sloan Program, $464 million in federal investment in power facilities and reservoir storage cannot be recovered

[22]Federal Power: Issues Related to the Divestiture of Federal Hydropower Resources (GAO/RCED-97-48, Mar. 31, 1997).

[23]According to Bureau officials, the bypasses ceased by November 1996 because of the installation of temperature control devices. These devices cost $80 million, according to Western.

[24]Under the concept of aid-to-irrigation, power revenues are to pay for the federal investment in irrigation facilities that the Secretary of the Interior deems to be beyond the irrigators' ability to repay.

until the associated irrigation projects come into commercial service. Because most of these irrigation projects are infeasible, the $464 million cannot be repaid. Without congressional action to force a reallocation of these costs from irrigation to power, or a related solution, recovery cannot take place. Recovery of these costs would place upward pressure on Western's electricity rates—potentially entailing a one-time increase of up to 14.6 percent. At a time that wholesale electric rates are decreasing, such increases in the PMAS' rates are uncompetitive and could erode the marketability of the federal power if they are numerous and continuous. Table 2.1 contains information about the circumstances surrounding the $1.4 billion at risk. Additional details on the situations at these six projects or systems are presented in appendix V.

Table 2.1: Risk of Nonrecovery of Federal Investment in Assets Associated With Southeastern, Southwestern, and Western, as of September 30, 1996

Dollars in millions

PMA	Project/ system	Risk category[a]	Dollars at risk	Explanation
Southeastern	Russell project	Remote, reasonably possible, probable	$518	Pumping units[b] (about 300 MW) are inoperable because of litigation over fish kills. As a result, federal capital investment has not been recovered through rates. Risk of loss is remote if units are placed into service, reasonably possible if inclusion of costs in rates makes the rates noncompetitive, and probable if these units do not come on line.[c]
Southwestern	Truman project	Remote, probable	31	Pumping capacity is not functioning because of design flaws and excessive fish kills. Risk of loss to government is remote only if the units are placed into service as designed in the near future. This is an unlikely event because they have been off-line since the early 1980s. Otherwise, the risk is probable.[d]
Western	Central Valley Project (rate-setting system)	Reasonably possible	267	Some portion of the investment is at risk for nonrecovery, mainly because environmental legislation requires a reallocation of water among its uses, which could result in restrictions on its use to generate power. At the same time, the Central Valley Project's power is faced with competition from nonfederal generators.[e]
Western	Pick-Sloan Missouri Basin Program (rate-setting system)	Probable	464	The federal investment in hydropower capacity and reservoir storage originally intended for use by future irrigation projects will not be repaid without congressional action. Under program statutes, recovery through rates cannot occur until the irrigation projects come into commercial service. According to the Bureau, almost all of these projects are infeasible.
Western	Washoe Project	Reasonably possible, probable	13	Since January 1996, Western has estimated that to cover Washoe's annual operating expenses (excluding depreciation), interest charges, and debt repayment, power from the project would have to be priced from 5.7 cents to 11 cents per kWh. However, Washoe's average revenue per kWh for energy sales in 1996 was only 1.02 cents per kWh. If Washoe's power continues to be marketed stand-alone, losses are probable, but they are reasonably possible if Western blends Washoe's rates with those of the Central Valley Project.[f]
Western	Mead-Phoenix (transmission project)	Reasonably possible, probable	95	Only about $71,000 of a $95 million federal investment has been recovered because demand had not materialized for power or transmission services. Losses to the government are probable if the services are marketed stand-alone, but reasonably possible if they are blended with other systems.
Total			$1,388	

(Table notes on next page)

[a]Based on Statement of Federal Financial Accounting Standard No. 5, Accounting for Liabilities of the Federal Government, if the chance that a contingent loss will occur is more likely than not, the loss is "probable"; if the chance is more than remote but less than probable, it is "reasonably possible"; if the chance is slight, it is "remote."

[b]Pumping units are designed to allow water, after it has passed through the generating units, to be pumped back into the reservoir during periods when demand for power is low. Then, the water can be used to produce power during periods of higher demand.

[c]According to DOE's Power Marketing Liaison Office, some unspecified portion of the $518 million investment in pumping units at this project will be recovered even if the units are never commercially operated. However, we believe this assertion overlooks the policy guidance contained in DOE Order RA 6120.2, which indicates that if the nonoperational units are not placed into commercial service, the power customers will not be required to repay the investment.

[d]According to the Corps, all repairs to off-line generating units will be completed by February 1999. According to DOE's Power Marketing Liaison Office, Southwestern can add to its power repayment study the power-related costs of this project's pumpback units even if the units are never operable. The Corps' ability to use the units in a pumping capability awaits the lifting of an injunction by the state of Missouri. However, we believe this assertion overlooks the policy guidance contained in DOE Order RA 6120.2, which indicates that if the nonoperational units are not placed into commercial service, the power customers will not be required to repay the investment.

[e]Western announced a decrease of over 20 percent, effective October 1, 1997, in the composite rates of power it markets from the Central Valley Project. FERC approved these rates on a final basis on January 8, 1998. These rate cuts were facilitated by renegotiating contracts that obligate Western to purchase power for its customers if the Project cannot supply enough power. The sustainability of these rate cuts, however, is uncertain, because of the effects of the Central Valley Project Improvement Act. Specifically, under the act's provisions, 800,000 acre feet of water in the Project must be managed for environmental purposes. According to the Bureau, an analysis of environmental impacts indicates that this change in how water is managed may result in a 5 percent reduction in hydropower production.

[f]According to DOE's Power Marketing Liaison Office, Western staff are proposing the blending of the costs of power from this project with the costs of the Central Valley Project after the year 2004.

Source: GAO/AIMD-97-110 and data provided by the Bureau, the Corps, DOE's Power Marketing Liaison Office, and Western.

Conclusions

More competitive electricity markets will offer new benefits to consumers while posing a special challenge to the federal government's program to generate and market power. With competition at the wholesale and retail levels, ratepayers are likely to enjoy unprecedented opportunities to choose from among several competing suppliers offering a variety of prices and services. However, the problems we have reported in recent years, combined with these market changes, should alert policymakers to take steps to protect the investment in the federal power assets.

Even in the absence of market changes, the agencies that provide power are over $50 billion in debt, including about $7 billion for the three PMAs. At the same time, the hydropower assets are degrading in terms of their availability to generate power, thereby making the power they generate less marketable. As competitive markets develop, some PMA customers may opt to buy from other suppliers if the PMAS' power is perceived as being increasingly unreliable. In addition, although the PMAS' power is very competitively priced, this advantage may not last. Specifically, competition is expected to cause market rates to fall. At the same time, the PMAS' rates need to cover the costs of environmental impacts downstream. If the PMAS' rates increase and the wholesale rates for power fall to the point where the two rates converge, the PMAS may lose customers to other suppliers. At the Central Valley Project and the Colorado River Storage Project, Western's wholesale power is already priced at levels competitors can challenge.

If the PMAS lose customers to other suppliers, then the risk increases that the federal investment in the power program will not be recovered. As documented in this chapter, for the three PMAS' projects and rate-setting systems, some portion of $1.4 billion is already at risk for nonrecovery. Although most of the risk to the $1.4 billion does not stem from increasing competition, the advent of competition does heighten the risk of nonrecovery. As discussed in the next chapter, options are available to the Congress and the agencies themselves to better recover costs and protect the federal investment, among other benefits.

Options for Operating Federal Hydropower Assets

The nation's electricity markets are undergoing significant changes, as the previous chapters have shown. The speed with which this widespread restructuring may be completed is uncertain; however, it is ongoing and will continue, perhaps at an accelerating pace, as proposals to expand competition to the retail electricity market continue to be made by national and state policymakers, electric utility interest groups, and the Congress. As the industry becomes less regulated and more competitive at both the wholesale and retail levels, nonfederal utilities and power suppliers have taken important steps to become competitive to survive. Federal power agencies also face the challenge of moving to a more competitive environment. The entities to whom the PMAS sell power, aware that they need to supply the cheapest available power to their own retail customers, have begun to pressure the PMAS, the Bureau, and the Corps to adopt business practices that are better suited to the new era. Furthermore, and perhaps most important, these agencies are under pressure to adapt to the new markets to reduce the risk that the multibillion-dollar federal investment in hydropower and other associated programs will not be repaid if federal power ultimately proves to be too unreliable and overpriced to be competitive. In this connection, a widening recognition exists today that options for operating federal hydropower assets need to be considered and ultimately implemented. Three broad options exist for addressing the federal hydropower program's operations:

- Preserve the status quo of federal ownership.
- Maintain federal control of the hydropower assets but manage them in a more businesslike manner.
- Divest the federal hydropower assets.

Preserve the Status Quo

The federal power program uses low-cost hydropower generated at major federal water projects to help meet the needs of the preference customers, many of which are located in rural areas. The power plants at these water projects are generally operated by the Bureau and the Corps—the operating agencies—and the power that exceeded the project's operational requirements is marketed by the PMAS, as described in chapter 1. Power is generated and marketed in a way that balances how the water is being used for the other purposes of the projects. Funding for the activities of the operating agencies and the three PMAS is subject to the annual congressional appropriation process under which the agencies obtain their funding for capital investments as well as for operations and maintenance expenses.

PMA and operating agency officials and representatives of the PMAS' customer associations have indicated a need to change how the federal hydropower program is being operated. They stated that the agencies' planning and budgeting processes do not provide sufficient, predictable, and timely funding to facilitate the repair of the federal power plants. In addition, they pointed to various administrative and legal requirements that they believe cause the PMAS and operating agencies to generate and market power in an unbusinesslike manner. In this connection, they have advocated ways to manage the federal hydropower assets, discussed in the next section, that will address these concerns.

Some representatives of the PMAS' preference customers have advocated defederalizing the PMAS and the federal generating assets as a way of improving their operating efficiency and availability. For example, according to an official of an association of Western's municipal power customers, the preference customers should purchase the federal generating and transmission assets of the Colorado River Storage Project in order to avoid the sharp rate increases that characterized Western's rates from the project since the late 1980s. It is important to note, however, that other preference customers continue to support continued federal ownership of the dams, reservoirs, and hydropower assets. These customers believe that, although some changes in the PMAS' current practices could lower operating costs and improve efficiencies, as a whole the PMAS have offered high-quality, low-cost services while balancing the diverse needs of the beneficiaries of the federal multi-use projects.

Moreover, representatives of investor-owned utilities or proponents of divestiture have questioned why the federal government continues to provide power in restructuring markets. First, electrifying rural areas was an important goal of the federal power program; however, this goal has been largely satisfied. Therefore, the need for the federal government's involvement is questionable. Second, competition likely would enable wholesale and retail customers to choose from among competing power suppliers. This possibility again questions the need for the federal government to sell power. Third, the issue of providing low-cost PMA power to portions of 34 states in the South and West where the preference customers of the PMAS are located, but not to other areas, is debatable. And fourth, IOUS and other critics of PMA power state that, as federal agencies, the PMAS have advantages that IOUS do not have and therefore would compete with their nonfederal parties on an uneven basis. For example, our work has shown that the PMAS have rates that do not recover all of the costs of generating, transmitting, and marketing power. Also, as federal agencies, the PMAS are not subject to income taxes or state regulatory oversight and have more flexible repayment and rate-setting methodologies. Fifth, the status quo continues the existing risk of nonrepayment of the federal investment.

Because of the stakes involved in changing the management and ownership of federal water projects and hydropower plants, maintaining the status quo affords policymakers the opportunity to make careful decisions about how to proceed. The federal government's role in balancing the multiple uses of water is important. It affects such things as how much water will be available to accommodate the expansion of metropolitan areas, how much water will be used to protect endangered species, and how much water will be needed to protect the harvesting of shellfish in the Apalachicola Bay, Florida. The Bureau and the Corps generate power while balancing these impacts. Any decisions that federal policymakers reach about changing how power is generated or how the water projects will be managed or owned will need to consider the impacts of the decisions on the uses of the water and the beneficiaries of the water projects. An advantage of the status quo is that it continues the federal role in balancing the multiple uses of the water and allows policymakers time to study these issues before they change the operations and/or ownership of the water and the power assets. Also, by preserving the existing multiple uses of the water projects and the projects' beneficiaries, the status quo avoids the debate that is likely to occur if the Congress reexamines the agreements reached decades ago on federal involvement in power. For example, the status quo continues federal power's role in helping promote the economies of rural areas, especially by providing inexpensive power to these areas for homes, businesses, municipalities, and irrigation. Many of the cooperatives that currently receive PMA power also have received direct loans or guarantees from RUS. According to Western officials, these cooperatives' financial health depends in part on the availability of low-cost PMA power. This is of significant interest to the Treasury because of its need to recoup the balance these PMA customers owe in RUS' loans or loan guarantees.[1]

[1]GAO/AIMD-97-110 and Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio (GAO/RCED-97-82, Apr. 11, 1997) discuss the federal government's risk associated with RUS' borrowers. In fiscal year 1995, for example, over 150 RUS' borrowers were preference customers of the three PMAs.

Under the status quo, the PMAs' revenues are to repay billions of dollars of the costs associated with joint[2] and nonpower benefits for purposes such as irrigation[3] and fish and wildlife protection. Because such benefits likely would not cease to exist if power revenues stopped paying for them, other sources of revenues would have to be located to fund them. In order to avoid increasing the federal deficit, one possible means of paying for these benefits would be for the Congress to fund them from increased tax receipts. However, if federal taxes and revenues could not be increased, then the Congress would need to offset the spending increase for the benefits by decreasing federal spending for other purposes. Alternatively, some costs could be allocated to categories that are not reimbursable through power rates or user fees—to flood control at the Pick-Sloan Program, for example. However, in such a case, additional revenues (such as new taxes or new user fees) would be needed to pay for the costs or offsetting budget cuts to avoid increasing the budget deficit. In these cases, because of the need to find new revenues, uncertainty about repayment of the full Treasury investment would increase.

Maintain Federal Ownership but Improve the Management of the Power Program

Many options exist for improving the operations of the hydropower program while continuing federal ownership. These options can be grouped in several different ways, including (1) improving the planning, budgeting, and funding for capital repairs of the federal hydropower assets; (2) changing the PMAs' power rates and repayment methodologies; (3) organizationally restructuring the federal hydropower program to improve its operating efficiency; and (4) eliminating the application of selected legal and administrative requirements to the federal program. In addition, the government could dispose of its high-cost hydropower projects. Some changes can be made by the PMAs and the operating agencies themselves, while others would require congressional action.

Improving the operating efficiency of the federal hydropower program would not fully respond to the concerns of the advocates of complete divestiture or privatization, who believe that the government should not participate in a commercial activity. Those concerns could be satisfied only if the hydropower assets were fully divested; however, improving their operations under federal ownership would better safeguard the

[2]Joint costs are costs associated with facilities that serve several purposes. For example, the dam impounds water not only for hydropower, but for other purposes of the water project—for instance, irrigation and recreation.

[3]For example, we reported that Western was responsible for repaying about $1.6 billion in irrigation-related costs from power revenues. See Federal Electric Power: Operating and Financial Status of DOE's Power Marketing Administrations (GAO/RCED/AIMD-96-9FS, Oct. 13, 1995).

federal investment while continuing to balance the existing multiple purposes of the projects. Adoption of these improvements may have immediate benefits or may be considered an interim step toward full divestiture, if the Congress proceeds with that option.

Improving Capital Planning, Budgeting, and Funding for Repairing the Federal Hydropower Assets

Federal agencies are traditionally funded through annual appropriations from the Congress. However, as stated in chapter 2, the federal budget process does not lend itself effectively to commercial activities. Under the current planning and budgeting process, the Bureau's and the Corps' project and field locations estimate the costs of and develop the budget proposals for capital repairs of not only hydropower facilities, but also dams, irrigation systems, navigation systems, and recreational facilities. Hydropower repairs may be assigned lower priorities than other items, and budget requests are also subjected to 10-percent to 15-percent reduction targets to reduce the federal deficit. Under these conditions, the PMAs' power customers believe, and our previous work showed, that funding for needed repairs is at best uncertain and at times is not available when it is needed.

Several alternatives present themselves for better ensuring that the federal hydropower resources are repaired in a timely fashion. Capital planning and budgeting could be instituted for the federal hydropower program. If the PMAs and the operating agencies were to adopt more businesslike capital planning and budgeting practices, they would be better able to systematically identify and fund improvements and repairs to their power systems. In addition to capital planning and budgeting, other approaches have been adopted. For instance, PMAs, operating agencies, and preference customers have reached agreements allowing customers to finance some capital repairs.

Institute Capital Planning and Budgeting

The Bureau and the Corps need to improve their planning and budgeting process to facilitate timely repairs of their hydropower facilities. The Corps' need was illustrated in our 1996 testimony on reliability issues at the Corps' hydropower plants in the Southeast.[4] The Corps recognized that long-term, comprehensive planning and budgeting systems are needed to identify and fund key repairs and rehabilitations at its hydroelectric power plants, especially in the current environment of static or declining budgets; however, under its current planning and budgeting system, its funding decisions cannot be based on such processes.

[4]GAO/T-RCED-96-180.

Operating under the federal budgeting process,[5] the Corps finds itself unable to ensure a predictable source of funding for capital projects at a time when its budget has been decreasing. Therefore, it gives priority to routine, ongoing maintenance and performs reactive, short-term repairs when its power plants experience unplanned outages.[6] The federal budgeting process does not lend itself to funding extensive repairs and rehabilitations; when these actions eventually become essential, the Corps' budgeting process requires extensive justifications that can take a year or longer to complete.

During the early 1990s, the Corps was beginning to address its planning and budgeting needs, for instance, by beginning to rank proposed repair and rehabilitation projects. This effort was suspended in fiscal year 1995, but the Corps' responsible headquarters official planned to direct the field locations to undertake the effort in time to be considered for the fiscal year 1998 budget. Moreover, in recognition of the need to spend more to repair and rehabilitate its hydropower plants, the Corps in fiscal years 1993 through 1997 requested appropriations for major rehabilitations of some of its hydropower plants. Ten major rehabilitation projects have been approved for funding during fiscal years 1993 to 2007, with a total cost of about $450 million. These projects are being funded from the Corps' Construction-General account generally over a multiyear period and do not need to be re-budgeted annually.

As described by Bureau officials, the Bureau's planning and budgeting process, like the Corps', is lengthy and complex, taking over 2 years to produce a known budget level. Because 10-percent to 15-percent budget cuts are applied to the initial budget and subsequent proposals made by the regions and their area offices, future funding levels are uncertain. For example, Bureau officials in the agency's Billings, Montana, regional office, described the lengthy budget process they expected to undergo to achieve a budget for fiscal year 2000. From the regional perspective, the process began in August 1997 when the regional office received the initial budget proposals from its area offices. During the ensuing 16 months, scheduled to end in December 1998, the area offices, the region, the Bureau's Denver Office, the Bureau's Washington Office, the Office of the Secretary of the Interior, and the Office of Management and Budget will

[5]Capital budgeting for federal agencies is discussed in GAO/AIMD-97-5 and Budget Issues: Incorporating an Investment Component in the Federal Budget (GAO/AIMD-94-40, Nov. 9, 1993).

[6]Problems in funding the maintenance of federal agencies' assets are discussed in Deferred Maintenance: Reporting Requirements and Identified Issues (GAO/AIMD-97-103R, May 23, 1997) and Deferred Maintenance Reporting: Challenges to Implementation (GAO/AIMD-98-42, Jan. 30, 1998).

review, discuss, and repeatedly revise the proposed area office and regional office budgets, resulting in a consolidated budget for the Bureau and the Department of the Interior. Although by December 1998 the Department will have informed the regional office of expected funding levels for fiscal year 2000, certainty about expected funding levels will not be attained until some time between February 1999, when the Office of Management and Budget will assemble and convey the President's budget to the Congress, and October 1, 1999, the start of fiscal year 2000.

Implement Alternative Forms of Financing

Funding from sources other than federal appropriations has been suggested as one option to improve how the PMAS and the operating agencies pay for repairs of the federal hydropower assets. Although use of nonfederal funds to finance federal agencies' operations is generally prohibited unless specifically authorized by the Congress,[7] several forms of alternative financing have been authorized by the Congress, according to agency officials.

Through one type of authorized arrangement, referred to, among other names, as "advance of funds," nonfederal entities, such as preference customers, pay for repairs and upgrades of the federal hydropower facilities. Under federal budget statutes, such funding must be ensured before work on a project can be started. For example, Western's customers are providing advance funding to renovate the generating units at the Bureau's Shasta power plant in the Central Valley Project. Under an agreement between the Bureau, Western, and the preference customers, the customers may finance up to $21 million and deposit the funds in an escrow account to pay for the work.[8] The Bureau accepts the customers' funds under the Contributed Funds Act.[9]

Customers may be repaid in various ways, including offsets to power rates under which (1) expenses funded from advances from customers are excluded from the revenue requirement for repayment purposes or (2) customers' monthly power bills are credited for the amount each customer paid to the escrow account. In the case of the Shasta power plant, the customers who contributed funds will be issued credits on their

[7]Agencies' use of funds from outside sources without specific authority is referred to as "augmentation of funds" and is prohibited.

[8]According to DOE, the Bureau awarded a contract for the Shasta rewind project for about $12.2 million in January 1997.

[9]The Corps' projects are not covered under the Contributed Funds Act. However, similar contributions can be now accepted to fund repairs to the Corps' assets with certain restrictions, according to the Army's General Counsel.

monthly power bills from Western; those that did not contribute funds will not be issued credits. According to the Bureau, this arrangement ensures that all customers contribute. When completed, the entire repair cost will have been expensed throughout the construction period with advance funding from PMA customers.

Under another form of alternative financing, referred to as "net billing," invoice amounts are netted out among parties who perform work or provide services for each other, resulting in the issuance of one check instead of multiple checks. Net billing has been used for purchased power and wheeling for several projects—Central Valley, Loveland Area, and Pick-Sloan, according to Western officials.[10] Western estimates that the use of net billing has reduced appropriation requirements by between $40 million to $50 million annually.

Under a variation of net billing, referred to as "bill crediting," a customer agrees to pay one or more of the PMA's bills in exchange for an equivalent credit on the customer's power bill. Bill crediting has the same uses as net billing. Western estimates that bill crediting has reduced appropriations' requirements by between $45 million to $60 million annually, mostly in the Central Valley Project,[11] and that increased use for the Loveland and Pick-Sloan projects could reduce the appropriations' requirements by between an additional $2 million to $7 million annually.

Supporters of alternative financing, among them officials from the Bureau, the Corps, the PMAS, and the PMAS' customers, note that its use allows repairs and improvements to be made more expeditiously and predictably than through the federal appropriations process. They believe that alternative financing could provide more certainty in funding repairs and help address problems such as deferred maintenance at Corps-operated plants that provide power marketed by Southeastern.[12] Alternative financing would also move certain costs out of the budget cycle, decreasing the need for appropriations that must be repaid through the PMAS' power revenues. For example, as of January 1998, Bonneville had entered into long-term agreements with the Bureau and the Corps that will allow Bonneville to directly fund about $150 million dollars in capital improvements and operations and maintenance of the federal hydropower

[10]Net billing is used pursuant to direction in House, Senate, and Conference Reports of the 84th Congress and the 1961 Public Works Appropriation Hearing, according to Western officials.

[11]Bill crediting is used pursuant to such legislation as the Reclamation Project Act of 1939 and the Act of August 26, 1937, according to Western officials.

[12]GAO/T-RCED-96-180.

assets in the Pacific Northwest. According to Bonneville, these arrangements will shorten the time needed to secure funding for repairs and maintenance and will remove maintenance as a funding item that must compete with other federal budget priorities. The agreements also promote coordination between Bonneville, the Bureau, and the Corps in budgeting for future maintenance and repairs. Bonneville estimates that this closer coordination will produce operating efficiencies that can reduce costs by up to about $48 million per year.

However, Corps and DOE officials cautioned that expanded use of alternative financing may not be prudent because, depending on how it is implemented, oversight by the Congress and the Office of Management and Budget may decrease. According to Bureau and DOE officials, the Congress could take action to foster oversight by the Congress and other entities. For example, Bureau officials believe that to provide for oversight, the agencies could be required to submit data on expenditures to the Office of Management and Budget and to the Congress.

Expanded use of alternative financing may require legislative action, especially for the projects operated by the Army's Corps of Engineers. In a July 1996 memorandum, the Army's Office of the General Counsel concluded that although the Army has some existing authority to accept funds from outside parties to finance replacements, improvements, and other work at the Corps' hydropower facilities, the use of these funds must be reviewed case by case and is limited to funds from states and their subdivisions. According to the memorandum, the Congress may have to enact more specific legislation to (1) clarify the terms under which such funds may be accepted, including the kind of work that they could pay for, and (2) establish the framework under which the Army, the PMAS, and the customers should proceed with such alternative financing.

Establish Additional Revolving Funds

The Congress could expand the use of revolving funds. Under one revolving fund arrangement, a fund established by a one-time permanent appropriation is replenished through revenues, which, in the case of the PMAS, are generated by the sale of power or other services and credited directly to the fund, instead of being replenished through annual appropriations. The Congress has authorized the use of these funds at such projects as the Colorado River Storage and Fort Peck projects to fund operation, maintenance, and replacement costs.[13]

[13]In addition, since 1974, Bonneville has operated without annual appropriations by using an agencywide revolving fund maintained by the Treasury and permanent Treasury borrowing authority. See GAO/RCED/AIMD-96-9FS and Bonneville Power Administration: Borrowing Practices and Financial Condition (GAO/AIMD-94-67BR, Apr. 19, 1994).

Proponents of revolving funds, including some officials of Western, the Bureau, and a PMA customer group, note that the funds allow repairs and improvements to be financed more expeditiously and predictably than the federal appropriations process does. Like alternative financing, revolving funds remove some costs from the budget cycle, thereby decreasing the need for reimbursable appropriations. Thus, revolving funds enable the federal power-related operations to be self-financing and also offer customers more opportunities to consult with the agencies on how to spend funds to repair and maintain the hydropower assets.

However, officials of PMA customer groups and the Office of Management and Budget also stated that the use of revolving funds could reduce oversight by external parties such as the Congress and the Office of Management and Budget and/or may allow repayment obligations to be incurred that are not routinely approved by these entities.[14] However, the Congress could be kept informed of the operating agencies' and the PMAS' spending plans through the annual appropriations process. For example, the PMAS could be required to submit their annual operations and maintenance budgets to the congressional oversight committees. A 1993 DOE legislative proposal, which was not enacted, would have provided for separate accounts established in the U.S. Treasury to be funded from all sources, including sales of power and other services as well as other collections by, contributions to, and appropriations for Southeastern, Southwestern, and Western. These PMAS, the Bureau, and the Corps would use these accounts to pay for the operations, maintenance, and rehabilitation of their power assets. The PMAS would have submitted their annual operations and maintenance (O&M) budgets to their budget committees, including estimates of the PMAS' and the operating agencies' O&M spending, project by project. Officials of the Bureau, Western, and a PMA customer group voiced concerns that revolving funds increase the likelihood that nonpower costs, such as environmental initiatives and repayment of obligations to Native Americans, will be added to the revenue requirements base, with rate impacts that are not fully apparent until later. For example, under bills proposed in both the House and the Senate, a potential future cost of up to about $4.5 million would be financed with payments from the Upper Colorado River Basin Fund to divest the lands, structures (including homes), and community infrastructure of the Bureau's Dutch John, Utah, community that the Secretaries of Agriculture and of the Interior identify as unnecessary.[15] A

[14]When it creates revolving funds, the Congress defines the way in which the funds are used, or it can amend the authorizing legislation for existing funds to cover additional uses for the funds.

[15]The community housed Bureau workers while the Flaming Gorge Dam was built.

Bureau official estimated that the agency may incur an additional $300,000 over a 2-year period to administer the transfer of assets.

In a related option, the Congress could authorize the three PMAs to use a portion of their revenues from power sales to directly fund statutorily defined hydropower-related activities of the operating agencies instead of turning the revenues over to the Treasury. The Energy Policy Act of 1992, for example, authorizes Bonneville to directly fund such activities at Bureau and Corps' hydropower projects in the Pacific Northwest. If the Congress authorizes other PMAs to directly fund hydropower assets of their operating agencies, the PMAs' access to nonappropriated funds, such as those provided to Bonneville, would be one way to pay for the projects. The Congress, however, may wish to consider limiting the types of projects that may be so funded, as it did for Bonneville.

Change the PMAs' Power Rates and Repayment Methodologies

Arguments can be made that the way the PMAs establish their revenue requirements and the way they set their rates need to be changed. As noted in our recent products,[16] for example, although generally following applicable laws and regulations, the PMAs' power rates are not recovering all of the costs associated with generating, transmitting, and marketing federal power. Such cost recovery is generally required by the Reclamation Project Act of 1939 and the Flood Control Act of 1944. DOE's cost recovery order (Order RA 6120.2), however, excludes certain costs associated with facilities that are not operational and is not specific about the recovery of other costs. The PMAs have consequently interpreted the order to exclude certain costs from their rates. In addition, the nonrepayment of some federal investments in hydropower capacity and other assets (most importantly, irrigation facilities) assigned to power for repayment raises the issue of whether these investments will be recovered under the current repayment methods. In addition, a question arises about whether the PMAs should be required to continue to market their power on the basis of cost-of-service pricing when other parts of the industry are being encouraged to market their wholesale power on a competitive basis.

This section discusses various ways that the PMAs could better recover the costs associated with the federal power program:

- Increasing PMAs' power rates.
- Charging rates based on competition.

[16] Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities (GAO/AIMD-96-145, Sept. 19, 1996) and GAO/AIMD-97-110.

- Changing the repayment methodology to recover the federal investment faster and decrease the risk of nonrepayment.
- Reallocating costs among the water projects' multiple purposes.
- Merging rate-setting systems to promote the repayment of costs at certain facilities.

Although these changes would address some unrecovered costs that we identified, they would not address all such costs. For example, such unrecovered costs as those associated with the incomplete irrigation facilities at the Pick-Sloan Program, facilities that are not operating because of a lawsuit at the Russell project, or environmental mitigation costs legally exempted from Western's rates at the Glen Canyon and Shasta dams would not be addressed.

Several of the methods listed could result in rate increases, but decisionmakers should consider that increasing the PMAs' rates is in the government's interest only as long as the rates do not rise to the point of being noncompetitive. Because the PMAs already sell power generated at a few of over 100 federal water projects whose power they market at prices at or near the prevailing market price, a rate increase could be counterproductive in these instances[17] and could not be sustained in a competitive marketplace. In addition, some are concerned that rate increases would harm rural communities and customers.

Increase Rates to Better Recover All Costs

Relying on Office of Management and Budget Circular A-25 on user fees as well as industry practices and federal accounting standards, our past reports identified a number of power-related costs that had not yet been fully recovered through the PMAs' electricity rates. Such costs include those for postretirement health benefits and a portion of Civil Service Retirement System benefits for current employees of the PMAs and the operating agencies, construction costs for some projects that were completed or under construction, and construction and O&M costs for hydropower facilities and water storage reservoirs that are infeasible and therefore not expected to be completed.[18]

Rates could be increased to fully recover some of these costs. For instance, the full costs associated with the postretirement health benefits

[17]Projects that generate power priced near or above the market rate or that face competition from other providers include the Central Valley Project and the Colorado River Storage Project, according to PMA and PMA customer association officials.

[18]GAO/AIMD-97-110; Federal Electricity Activities: Appendixes to the Federal Government's Net Cost and Potential for Future Losses, Volume 2 (GAO/AIMD-97-110A, Sept. 19, 1997); GAO/AIMD-96-145; and GAO/T-RCED-96-142.

and the Civil Service Retirement System benefits could be recovered through power rates. The three PMAs will begin the process of recovering pension and postretirement health benefit costs by including the unfunded liability of the Civil Service Retirement System and postretirement health and life insurance costs of power-related employees in their power repayment studies, beginning in fiscal year 1998.[19]

Revenues from rate increases could also pay for unrecovered capital costs for projects that are under construction or not yet in commercial operation when those projects are brought on line. Under DOE's repayment guidance, the recovery of some federal investments in hydropower has been deferred until projects are completed and placed into commercial operation. These costs are to be repaid when these projects come on line, although rate increases may be substantial. For example, a Southeastern official stated that the costs for the nonoperational pumping units at the Corps' Russell project, which he estimated at about $528 million as of August 1997, are not yet subject to repayment. Because of litigation over large fish kills, these units have not been allowed to operate commercially and these costs have not been included in Southeastern's rates. However, if the nonoperational units come on line, these costs would be recovered through rates. The resulting rate increase for customers of that particular rate-setting system may be as high as 25 percent, but in this instance the power would still be competitively priced, according to this official.

Charge Rates Based on Competition

The industry is being encouraged to base its power rates on a competitive basis rather than on cost of service. Therefore, the Congress could enact legislation authorizing or directing the PMAs to change from cost-of-service rates to rates based on competition.[20] In accordance with legislation, the PMAs are to set their rates at the lowest possible level consistent with sound business principles and market their power primarily to preference customers. Because the three PMAs' overall average revenue per kWh is at least 40 percent below existing market rates,[21] charging market rates for

[19]Bonneville plans to begin recovering these costs in fiscal year 1998; full recovery is planned beginning in fiscal year 2002. Consistent with current policies and law, the PMAs do not plan to recover pre-fiscal year 1998 net costs.

[20]Except as otherwise provided by law, the PMAs are directed to generate revenues sufficient to recover all costs incurred as a result of generating, transmitting, and marketing electric power, including repayment of the federal investment and other debt with interest. In addition, legislation makes Bonneville and Western responsible for repaying, through power revenues, some irrigation costs associated with the hydropower projects. DOE requires each PMA to annually prepare a repayment study to test the adequacy of its rates and to show, among other things, estimated revenues and expenses, estimated payments on the federal investment, and the total amount of federal investment to be repaid.

[21]GAO/RCED/AIMD-96-9FS; GAO/AIMD-96-145; and GAO/AIMD-97-110 and 110A.

PMA power would most likely cause the PMAs' rates to rise.[22] With higher rates, the PMAs' revenue would be likely to increase and, consequently, the risk of nonrepayment of the federal investment would be likely to decrease as long as the rates remain competitive relative to prevailing market rates.

Change the Repayment Methodology to Recover Federal Investment More Quickly

The Congress or the Secretary of Energy could require the methodology for repaying PMA debt to be changed in order to recover the federal investment more quickly. Such a change could increase the PMAs' rates and revenues as well as the rate of repayment to the Treasury. Under DOE's current policy and consistent with applicable laws, the PMAs may defer repayment of annual expenses when power revenues do not meet repayment needs during low water years. Deferred annual expenses accrue interest at a current interest rate until they are repaid and generally must be repaid prior to the PMAs' repaying the principal investment. When repaying principal investment, the PMAs generally must repay their highest interest-bearing debt first rather than the oldest debt.[23] These provisions establish some of the financing flexibility the PMAs need because their revenue reflects the year-to-year variability of water flows and hydropower generation; however, they also result in rates that are lower than they otherwise would be, slower repayment of the federal investment, and a net cost to the Treasury because interest rates on the outstanding federal investment are substantially below the rates Treasury incurs to provide funding to the PMAs and other federal programs. Repaying the federal investment faster would decrease the Treasury's interest costs and the amount at risk for nonrepayment. However, as for any alternative that increases rates, policymakers would need to consider the impact on the PMAs' customers and their region.

Reallocate Costs Among the Projects' Multiple Purposes

The Congress, or in some cases the operating agencies, could revise the formulas used to allocate costs currently assigned to the multiple purposes of the federal water projects or the "joint costs" (those shared among more than one of the purposes—for example, the capital costs associated with the dam). In some cases, this action would reduce the capital investment that would have to be repaid through the rates the PMAs charge for electricity. For example, officials of the Corps and Western's preference customers noted that some projects currently allocate little or no costs to recreation or water quality, even though these categories have become

[22]As noted earlier, rates for a few projects are already at or near the market price. Also, prices above the market rate could not be sustained in a competitive marketplace.

[23]Policies Governing Bonneville Power Administration's Repayment of Federal Investment Still Need Revision (GAO/RCED-84-25, Oct. 26, 1983); GAO/RCED/AIMD-96-9FS; GAO/AIMD-96-145; and GAO/AIMD-97-110.

increasingly important purposes since the operating agencies prepared the project cost allocations. Through reallocation, a portion of the costs assigned to power would be reassigned to recreation and the electric rates could be lowered accordingly.

However, reallocations could result in some costs that are currently being repaid through power revenues—for example, most irrigation-related costs—needing to be repaid through other means.[24] Absent action by the Congress or the operating agencies to institute or increase existing user fees for the activities currently repaid through power revenues, these costs could end up not being repaid. Thus, while the PMAS' ratepayers could be relieved of the repayment burden of costs no longer assigned to power, the federal taxpayer may end up bearing the burden instead. Also, in commenting on our draft report, DOE's Power Marketing Liaison Office noted that the equity of certain project beneficiaries (for example, power customers) having to repay more than their fair share of multipurpose costs also needs to be addressed.

In some cases, congressional action would be required to authorize a reallocation of costs. For example, as of September 30, 1994, the federal government had about $454 million in federal investment (1) in the Pick-Sloan Program's hydropower capacity that was initially designed to be used by future irrigation projects and (2) in the costs associated with storing water for these projects.[25] Although these costs are scheduled to be repaid through Western's power revenues, under Western's statutory repayment principles, these costs, which we estimated at $464 million as of September 30, 1996, cannot be recovered unless the associated irrigation projects come into service. According to the Bureau, however, almost all of these planned irrigation projects are infeasible and are unlikely to be completed. Reallocating the $464 million from irrigation to hydropower would help ensure full recovery, but without legislative action to do so, it is probable that Western's power rates will not recover the principal or any interest on it.

Merge Rate-Setting Systems

For some facilities, rate-setting systems could be merged to expedite repayment. For example, at two facilities—the Stampede Powerplant at the Bureau's Washoe Project and the Mead-Phoenix Transmission Line, which is partially owned by Western, with a combined federal investment of at least $108 million, as of September 30, 1996—Western generated

[24]As of September 30, 1994, the Secretary of the Interior had assigned over $2.4 billion in irrigation-related costs to Bonneville and Western for repayment through power revenues.

[25]GAO/T-RCED-96-142.

insufficient income to recover capital and operating costs. Western officials are considering a merger of the Washoe and Mead-Phoenix rates with others, resulting in blended rates and increasing somewhat the likelihood of full repayment of the federal investment.[26]

Restructure the Federal Hydropower Program to Improve Operating Efficiency

In recognition of the changing power markets, the Congress could restructure the PMAS organizationally to better enable them to compete. It can be argued that such changes could provide the PMAS with the flexibility to respond better to market changes and to the needs of their customers, thereby helping to ensure the PMAS' survival and the repayment of the federal investment. It can also be argued that the PMAS' federal responsibilities should be continued because of the need to balance the multiple purposes of the water projects. Also, restructuring the PMAS may be seen as an interim step to privatizing them and the operating agencies' hydropower-related assets.

However, absent congressional action and depending on how the program might be reorganized, any restructuring of the PMAS that increases their operational independence may decrease congressional and other oversight. TVA, a wholly owned federal utility with little external oversight, used its financial ties to the federal government and its operational independence to embark on an ambitious nuclear power building program that resulted in nearly $28 billion in debt, as of September 30, 1996. This debt puts TVA at a competitive disadvantage, especially if the Congress were to revise legislation and require TVA to compete with other power suppliers. TVA's experience highlights the need for the Congress to carefully consider what oversight would be needed before allowing the PMAS to restructure to be more competitive.

Reorganize the PMAs as Federally Owned Corporations

The Congress could enact laws to authorize the PMAS to operate as federally owned corporations. This type of restructuring, "corporatization," would allow a government entity that serves a public function of a predominantly business nature to operate in a more efficient, businesslike fashion, while preserving the public service goals that are unique to federal agencies (for example, revenues from Western's sale of

[26]GAO/AIMD-97-110A.

power are scheduled to pay for most of the federal investment in irrigation facilities).[27]

Establishing a PMA as a government corporation has been formally proposed in recent years. In 1994, a proposal was drafted to corporatize Bonneville as a way to help maintain its competitiveness. Bonneville has been faced with competition from alternative power sources with lower costs, debt that exceeded $17 billion as of September 30, 1996, and upward pressure on its costs, caused in part by expanded, more costly efforts to protect salmon. The proposal was based on a recommendation in a National Academy of Public Administration report that examined alternative structures to achieve the maximum efficiency and effectiveness at Bonneville. The administration considered legislation to make Bonneville a wholly owned government corporation under the Government Corporation Control Act. This action was intended to increase Bonneville's flexibility over personnel; procurement; property management; and budgetary, litigation, and claims settlement functions and to enable Bonneville to compete more effectively in electric power markets.[28] Bonneville estimated that the savings from corporatization would have been as much as $30 million annually. In that the other three PMAs' operations are much smaller than Bonneville's,[29] the estimated savings from their corporatization would likely be smaller.

Corporatization may permit repairs and improvements to be financed more expeditiously and predictably than the federal appropriations process. Presuming that a revolving fund would be established as part of the corporatization, the corporation could operate in a businesslike fashion, without having to submit a budget request for annual appropriations to finance operations. Although the electric utility industry is now unbundling its services, depending on how the government corporation was structured, the generation, transmission, and marketing aspects could be put under one agency, possibly reducing overhead. Each PMA could be established as a separate corporation or two or more of the

[27]A corporate form of organization may be appropriate for the administration of government programs that are predominantly of a business nature, produce revenue and are potentially self-sustaining, involve a large number of businesslike transactions with the public, and require a greater flexibility than the customary type of appropriations budget ordinarily permits. See Government Corporations: Profiles of Existing Government Corporations (GAO/GGD-96-14, Dec. 13, 1995).

[28]The draft bill to corporatize Bonneville contained many specific statutory and regulatory exemptions, which are described in detail in Government Corporations: Profiles of Recent Proposals (GAO/GGD-95-57FS, Mar. 30, 1995).

[29]For fiscal year 1995, Bonneville had total operating revenues of about $2.4 billion compared with about $159 million for Southeastern, $114 million for Southwestern, and $713 million for Western, according to the PMAs' annual reports.

PMAS—Southeastern and Southwestern, for instance, could be merged. The latter option may afford the economies of scale necessary to make the new corporation or corporations viable, according to a Corps headquarters official. Alternatively, distinct federal rate-setting systems could be corporatized as separate entities from the rest of the PMA. Western officials responsible for marketing power from the Bureau's power plants within the Salt Lake City Integrated Projects—the Colorado River Storage Project plus the Provo River, Falcon-Amistad, and other projects that are aggregated for rate-setting purposes—suggested that their marketing program could be corporatized. They said that it already benefits from substantial operating and budgeting independence because its operations are financed from a revolving fund. However, in its response to our draft report, DOE's Power Marketing Liaison Office stated that it is not Western's policy to support the corporatization of this marketing program at this time.

If the government's objective is to eventually end its participation in a "commercial" activity, corporatization could be an interim step toward divestiture of its hydropower-related assets. In a 1995 report on the privatization or divestiture practices of other nations, we noted that the five nations[30] we reviewed generally (1) converted government agencies or functions into a corporate form before privatizing them or (2) primarily privatized entities already in a corporate form.[31] Converting a government department into a corporate entity, followed in many cases by a privatization, has been common worldwide during the past decade.

In New Zealand, for example, the government included a set of reform principles designed to improve performance in the delivery of public sector goods and services in the State-Owned Enterprises Act of 1986. The government anticipated that entities corporatized under this act would be subject to the same regulation, antitrust, tax, and company law as private enterprise. The restructuring of the electricity industry commenced with the corporatization of the government's generation and transmission capacity in 1987, corporatization of the retail power companies in 1993, full deregulation of the retail sector in 1993 and 1994, and establishment of a competitive wholesale electricity market in 1996. According to a former New Zealand government official, the government privatized seven small government-owned generating projects in 1995. Additional privatizations

[30]The five nations are Canada, France, Mexico, New Zealand, and the United Kingdom.

[31]Budget Issues: Privatization/Divestiture Practices in Other Nations (GAO/AIMD-96-23, Dec. 15, 1995). See also Deficit Reduction: Experiences of Other Nations (GAO/AIMD-95-30, Dec. 13, 1994).

of generation facilities, while possible, are not anticipated, according to New Zealand's Energy and Finance Ministers.

The changes in electricity rates since the New Zealand's restructuring of the electricity sector are noteworthy, according to a former New Zealand government official we interviewed. Although very large rate increases had been feared for farmers, for example, rural rates declined by about 40 percent in real terms from 1987, when the reform process started, to 1994, according to one study.[32] Cross subsidies between customer classes are reported to be greatly reduced. Over a longer term, inflation-adjusted retail domestic (residential) rates increased by about 5 percent to 15 percent from 1985 through 1997 and from about 16 percent to 20 percent from 1990 through 1997, according to the New Zealand Ministry of Commerce. Commercial rates, on the other hand, decreased by about 20 percent to 28 percent from 1985 through 1997 and by about 1 percent to 9 percent from 1990 through 1997.[33]

In the United States, experience with such conversions after interim corporatization of government activities has been limited. For example, the Congress enacted legislation in 1992 to corporatize DOE's uranium enrichment operations as the U.S. Enrichment Corporation[34] in a transitional step toward eventual privatization.[35] Similarly, a bill now in House committees would convert the three PMAs into corporations as an interim step toward their privatization.

Despite the advantages, creation of a government corporation could significantly reduce the amount of oversight the entity receives. In the past, we have suggested that the Congress strengthen the oversight and accountability of government corporations.[36] For example, over the years, we[37] and others, have characterized TVA, an existing wholly owned federal

[32]"The Impact of Electricity Reforms on Rural New Zealand," P. J. Farley, 1994.

[33]Comparable data for industrial rates were not available.

[34]See Uranium Enrichment: Observations on the Privatization of the United States Enrichment Corporation (GAO/T-RCED-95-116, Feb. 24, 1995) and Uranium Enrichment: Activities Leading to Establishment of the U.S. Enrichment Corporation (GAO/RCED-94-227FS, June 27, 1994).

[35]The corporation was formed in 1993 and its sale was authorized by the President in July 1997. However, as of February 1998, the transfer to private status, which is expected to be completed in 1998, had not been completed.

[36]Congress Should Consider Revising Basic Corporate Control Laws (GAO/PAD-83-3, Apr. 6, 1983).

[37]GAO/AIMD/RCED-95-134; Triennial Assessment of the Tennessee Valley Authority—Fiscal Years 1980-82 (GAO/RCED-83-123, Apr. 15, 1983); and Tennessee Valley Authority—Options for Oversight (GAO/EMD-82-54, Mar. 19, 1982).

corporation, as having insufficient independent oversight.[38] Some have noted, moreover, that an entity that resulted from a merger of, for instance, the Bureau's water management and power generating responsibilities with Western's power marketing responsibility could experience conflicts among these three different roles.

Consolidate Power-Related Functions Under One Agency

The Congress could consolidate the power-related operations of the operating agencies and the PMAS. Some operational improvements and cost savings could result. Officials at the Bureau's Denver office recommended that Western's assets be returned to the Bureau so that the Bureau could better coordinate the multiple purposes of the water projects, while reducing overhead.[39] They estimate that overhead costs could be reduced by up to 30 percent if Western's power marketing activities were consolidated within the Bureau.

Although the Bureau and the Corps previously marketed the power they generate, concerns exist about reconsolidating the power marketing function in these agencies because of the need to balance the needs of hydropower with the needs of the other activities the agencies pursue. Each agency has it own priorities, which do not always favor maximizing power revenues. For example, the Congress may provide funds to the Corps to upgrade a failing generator, but if a key lock in the Corps' navigation system were disabled, the Corps might divert the funds intended for the generator to the lock. This could prolong an outage at the power plant and cause the government to lose revenue. Although a Corps headquarters official stated that this scenario occurred infrequently, he said that a repair project may be deferred because of conflicting priorities. At the same time, if the power generating activities of the Corps and the Bureau were consolidated within the PMAS, the PMAS, which have a primary mission of marketing power, may inadequately consider the other purposes of the water projects when operating the power plants. In addition, consolidations clash with the developing trend among vertically integrated power utilities to segregate generation, transmission, distribution, and ancillary services.

[38]A bill has been introduced in a Senate Committee to address this issue by replacing TVA's current three-member board of directors with a nine-member board.

[39]The Bureau owned and operated Western's marketing and transmission assets before Western's creation in 1977.

Eliminate Selected Legal and Administrative Requirements

Bureau, Corps, and PMA officials believe that some of the legal and administrative requirements that their agencies must follow cause them to operate in an unbusinesslike fashion and may cause the PMAS' power rates to increase. For example, aware of the need to operate more efficiently, in February 1996 Western chartered an internal study designed to identify and address laws, regulations, and rules that it determined to be counterproductive to its functioning in a businesslike manner. Although many of the study's recommendations are administrative in nature, Western identified opportunities to improve its performance that ranged from a few thousand dollars to millions of dollars. For example, the report on the study recommends that Western request an exemption from DOE's requirement to report quarterly on safety. Western contends the report is of no value, but exempting it from this requirement could save Western $6,630 annually. In another example, Western estimated that if it used a credit card to purchase supplies and services instead of purchase orders, it could save over $500,000 annually. In an example that would require legislative action, exempting Western from the statutory requirements in the Federal Acquisition Regulations about taking sealed bids for procurements could save the agency $115,600 annually. Of more consequence, the Congress could allow Western to pay prevailing local area wages instead of those required by the Service Contract Act of 1965. The report states that such an amendment could save Western about $6.2 million annually. The scope of Western's study included the Code of Federal Regulations, the Federal Acquisition Regulations, executive orders, DOE's orders and guidelines, and other directives.[40]

Dispose of High-Cost Hydropower Projects

The Congress could pass legislation that would allow the Bureau and the Corps to divest themselves of projects that have power generating costs that exceed the costs and rates of their rate-setting system. Officials from the Bureau, officials from two of Western's customer groups, and representatives of some of Southwestern's customers suggested that the PMAS could operate more efficiently and reduce pressure to raise power rates if the operating agencies were allowed to dispose of several plants that produce higher-cost power.[41] Collectively, they suggested that some of the hydropower plants at the Bureau's Collbran, Dolores, Loveland Area, and Rio Grande projects as candidates for disposal. According to

[40]In January 1998, a draft report was released for public comment that recommended $159 million in cost savings for Bonneville, which included at least $10 million annually from legislative changes in procurement and personnel laws designed to improve administrative effectiveness and efficiency.

[41]According to the Bureau, its divestment policy suggests that it can only divest isolated or remote water projects that do not have international or interstate ramifications.

Bureau officials, some of these projects associated with the Colorado River Storage Project produce power at costs ranging from about 3.5 to 6 cents per kWh, whereas Western sells power at a composite firm rate of about 2 cents per kWh for the Colorado River Storage Project. According to a Corps official, one obvious problem with this option is finding a willing buyer for these inefficient units. Also, to the extent that power revenues cease to pay for some of the federal investment in constructing these units, the taxpayers would assume a larger burden. Whether the government's investment in these projects is fully recovered depends on the terms and conditions of the sale and the resulting price received for the assets.

Divest the Federal Hydropower Assets

Consistent with the philosophy that the government should not be involved in commercial activities that are best left to the nonfederal or private sector, the Congress could enact legislation to divest the PMAs and the government's hydropower assets. As we concluded in our March 1997 report, divesting the federal hydropower assets, while possible, would be complicated for several reasons.[42] Any divestiture of hydropower-related assets would need to balance the multiple purposes of the water projects that limit and define how water is released through the turbines, how and when electricity can be generated, and in what quantities. These federal responsibilities would not necessarily terminate after a divestiture. Other factors would also have to be accommodated. These factors include the types of assets being divested, the conditions attached to the sale and the use of the assets after the divestiture, the operating conditions of the assets, the sales mechanism used, and the impact of the divestiture on regional economies, including the impact on regional electricity prices. Of particular note, the impact of a divestiture on the future rates of the preference customers would have to be considered. If the PMAs were privatized, rates would likely increase to varying degrees for most of the current preference customers. Together, these factors complicate the sale of federal hydropower assets and at the same time could affect the willingness of potential buyers to bid on the federal hydropower assets and the price the government could obtain for them. It should be noted that customers themselves have proposed defederalization of the federal hydropower assets. For example, in 1995, 37 of Western's preference customers advocated an arrangement whereby they would purchase, lease, or obtain other rights to the federal hydropower generating assets within the Boulder Canyon and Parker-Davis projects, as well as certain transmission projects. According to a representative of these customers,

[42] GAO/RCED-97-48.

this proposal was made to prevent an investor-owned utility from acquiring the federal power resources and was also a reaction against other privatization proposals that were being presented at that time.

Accommodating Multiple Purposes and Other Public Policy Factors

With very few exceptions, federal hydropower projects have multiple purposes specified in their authorizing legislation. For example, the Corps' Fort Peck project on the Missouri River in Montana has hydropower as a purpose as well as providing for fish and wildlife habitat, flood control, irrigation, navigation, recreation, water quality, and water supply. Multiple purposes are often complementary but are sometimes at odds. For example, water is stored in and released from a reservoir to provide for recreation, but its release through the turbines could be scheduled in a way that is intended to maximize revenue. In contrast, Western's Billings, Montana, office forecasts decreases in power revenues in the long-term because water, which would otherwise be used to generate electricity, will be increasingly used for irrigation and for other purposes. In its fiscal year 1995 repayment study, Western predicted that revenues from the sale of hydropower would decrease from about $253 million in 2001 to about $213 million (in constant 1995 dollars) in fiscal year 2080 for the Pick-Sloan Program.

At the Bureau's and the Corps' water projects, power generation is defined and constrained by the requirement to manage the water for other purposes. The Bureau, for instance, at some projects has restricted releases through the turbines to mitigate environmental impacts downstream. The need to manage water for multiple purposes and to generate hydropower in a way that balances other purposes would have to be accommodated even after a divestiture occurs, absent congressional action.

In addition, the water rights of Native Americans and of states would need to be accommodated in the event of a divestiture. According to Bureau officials, Native Americans' rights to water at some federal water projects are the earliest and thus supersede the use of water for other purposes, including hydropower generation. As an example, Bureau officials cited a legal settlement with tribal entities of the Fort Peck Reservation in Montana that includes the right to about 1 million acre-feet of water from the Missouri River.[43] In addition, according to DOE's Power Marketing Liaison Office, a divestiture may have to address how to transfer out of

[43]One acre-foot is the amount of water that it would take to cover 1 acre of land with water to a depth of 1 foot.

federal ownership the transmission lines and rights-of-way that traverse tribal lands. The tribes may be concerned about the transfer or sale of such lines to private parties.

States also have water rights, and the Bureau and the Corps are increasingly arbitrating between the claims of various states. For example, for several years, Alabama, Florida, and Georgia have been contesting the uses of water in two river basins in the Southeast that the Corps manages.

Regulation of Hydropower Assets Would Be Affected by the Types of Assets Divested

As stated in our March 1997 report, the three general ways the government could divest itself of its hydropower assets are divesting (1) only the PMAS (including the right to market power and any associated federally owned transmission assets); (2) the PMAS and the generating assets of the Bureau or the Corps or both; and (3) the PMAS, the generating assets, and the balance of the projects (for example, the dams and the reservoirs).[44] Divesting combinations of these assets is also possible. In general, divesting only the PMAS and the hydropower generating assets would be less complicated than divesting the balance of the projects because the first two alternatives retain the Bureau and the Corps in their role of managing how water is used and in balancing the projects' multiple purposes. The kinds of assets divested will influence the regulatory issues accompanying a divestiture.

Many options for regulating the operations of divested hydropower assets exist, including regulatory regimes that could be established by federal, state, or regional authorities. FERC, which currently licenses the operation of nonfederal hydropower assets, primarily regulates the reasonableness of wholesale rates charged by the PMAS but does not provide more detailed oversight. According to FERC officials, FERC has experience regulating the multipurpose aspects of water development at over 1,600 projects nationwide pursuant to much the same multiple-use standards as apply to federal projects. FERC, however, does not have complete authority to set regulatory requirements. Other federal and state agencies, through FERC's regulatory process, may impose mandatory conditions on FERC's licenses, which complicate FERC's licensing process.

If only the PMAS (including their rights to sell power and any transmission lines) were divested, then the Bureau and the Corps would continue to operate the hydropower plants, dams, and reservoirs in accordance with existing plans, guidelines, and regulations. In such a case, the buyer would

[44]GAO/RCED-97-48.

not need a FERC-issued license; the Bureau and the Corps would continue to manage the water as in the past, the existing restrictions would be likely to remain in effect, and the buyer would market the power subject to the same conditions as the former PMA. According to FERC officials, they prefer to license all of a project's features that have a role in power production.[45]

However, if the power plants were divested as well, the new owner would be required to obtain an operating license from FERC, unless this requirement was specifically exempted by law.[46] Licensing a divested plant could take a long time. We reported, for example, that the median processing time for 111 projects applying for relicensing between January 1982 and May 1992 was 2.5 years.[47] Some had taken as long as 10 to 15 years. In January 1998, a FERC official told us that the median time to relicense over 150 projects whose licenses expired in 1993—the most recent data FERC had analyzed—was about 30 months.

If a divestiture involves a PMA, the power plants, and the balance of the water projects (most importantly, the dams and reservoirs), the Bureau and the Corps would no longer fill the role of specifying the operating conditions of the project. Instead, safeguards for the multiple uses of the water would primarily be contained in the conditions FERC would attach to the operating license pursuant to the Federal Power Act. In such an event, in licensing the hydropower plant, FERC would be required to weigh the plant's impact on such aspects as the environment and recreation. Licensing would therefore be complicated by the need to complete a number of studies on the power plant's impact on fish, plant, and wildlife species; water use and quality; and any nearby cultural and archeological resources. Moreover, the government of each affected state would have the opportunity to issue a water quality certification.

FERC officials also cautioned that if power plants, dams, and reservoirs were sold, then FERC's licensing process could revisit the management and uses of the water pursuant to the Federal Power Act and possibly change the operation of the project, potentially affecting power generation. In connection with this issue, the executive director of the National Hydropower Association stated that nonfederal hydropower plants are

[45]See FERC testimony of June 10 and October 7, 1997, before the Subcommittee on Water and Power, Senate Committee on Energy and Natural Resources.

[46]For example, a bill currently before a House committee would specifically grant the new owner a conditional 10-year license for continued operation and maintenance of the hydropower facility. Thereafter, a FERC license would have to be obtained.

[47]Electricity Regulation: Electric Consumers Protection Act's Effects on Licensing Hydroelectric Dams (GAO/RCED-92-246, Sept. 18, 1992).

losing generating capacity because of environmental restrictions or mitigations that are attached as conditions to their operating licenses as FERC relicenses those plants. Moreover, according to a September 1997 report by DOE's Idaho National Engineering Laboratory,[48] at the time of relicensing, 96 percent of the peaking projects relicensed since 1987 have had their ability to meet peak demand reduced. Of the 52 projects that were relicensed from 1987 to 1996, FERC added capacity to only 4 projects, but the remaining 48 projects had their ability to meet peak demand reduced by from 0.4 to 54.3 percent of their previous capacity: the average reduction was 6 percent. Also, FERC's review of over 130 projects licensed from the 157 applications filed in 1991 shows that while generating capacity had a very small increase, actual electricity generation had a very small decrease—less than 1 percent.

Trade-Offs Exist Between the Conditions Attached to the Sale and Use of Assets and the Bids Received

The explicit and implicit liabilities borne by the government and which of those liabilities would transfer to a buyer would also affect the price obtained for the federal power assets. Sales of some or all of the hydropower assets—at prices that exceed the value to the government—would produce budgetary savings in the long run, according to a November 1997 report by the Congressional Budget Office.[49] The report estimates that the combined assets of the three PMAs may be worth between about $8 billion and $11 billion. A sale could also result in a future stream of tax payments to the Treasury, also depending on the divestiture's terms and conditions. However, the report states that losses are possible, depending on the terms and conditions of the sale. In addition, as a matter of general principle, policymakers would need to take into consideration the fact that assets that are sold with many or relatively onerous restrictions (from the viewpoint of a prospective purchaser) or uncertainties about future operations are correspondingly less attractive and are likely to sell for less. While the government may still choose to place restrictions or to assign or retain certain liabilities, the financial consequences in terms of the sale price should be assessed.

If the government's objective is to obtain the maximum possible price for its assets, the government could retain certain liabilities that could reduce risks to potential buyers. In some cases, the federal government could be in a better position than the buyer to bear certain risks. For instance, in the proposed divestiture of the U.S. Enrichment Corporation, the

[48] Hydropower Resources at Risk: The Status of Hydropower Regulation and Development—1997 (DOE/ID-10603, Sept. 1997).

[49] Should the Federal Government Sell Electricity?, Nov. 1997.

government would retain liability for the environmental cleanup associated with the prior production of enriched uranium. According to a contractor's report, decontamination and decommissioning activities at uranium enrichment plants could cost as much as $17.4 billion in 1994 constant dollars. At some hydropower projects, available generating capacity has been diminished by up to one-third because of the need to mitigate environmental impacts downstream. Buyers may discount any prices they offer because of the loss of available generating capacity unless the government assumes the liability for mitigating environmental impacts. In addition, in the case of the federal hydropower assets, uncertainty about future operating conditions because of potential environmental liabilities may discourage bidding or result in lower prices than if the federal government assumes some of the liabilities. For instance, one provision of the Central Valley Project Improvement Act directs the Secretary of the Interior to manage annually 800,000 acre-feet of water for environmental purposes authorized by the act.[50] According to the Bureau, an analysis of the environmental impacts indicates that hydropower generation may be reduced by about 5 percent. Were the government to divest the project's assets, it might agree to limit the effect of water use restrictions on potential buyers for a specific period and to specify changes in water use restrictions over time to reduce the uncertainty the buyer would face.

If the government's objective is to expedite the divestiture on terms that would less adversely affect the projects' beneficiaries, getting the highest possible price for the assets might be a secondary consideration. For example, although a decision to limit bidders on particular assets to certain geographic areas would foster a goal of local or regional control of those assets and expedite a transfer, it could reduce the proceeds from the sale if other potentially interested buyers were precluded from making offers. In the ongoing divestiture of the Alaska Power Administration, an overriding concern is to protect that PMA's ratepayers from increases in electricity rates. Decisionmakers therefore restricted the eligibility of bidders to only nonfederal entities from within the state of Alaska. It also accepted a sale price approximating the present value of future principal and interest payments that the Treasury would have received instead of establishing the price by selling the assets in an open, more competitive fashion to the highest bidder.

[50]In addition, two other provisions could eventually allocate up to another 600,000 acre-feet of water for fish and wildlife mitigation at wetland refuges and the Trinity River, according to estimates by the Congressional Budget Office.

Trade-Offs Between Assets' Operating Conditions and the Need to Improve Them Must Be Considered in the Event of a Divestiture

Assets that are in better operating condition are more likely to attract higher bids than assets in poor condition. We testified in July 1996 that federal hydropower plants in the Southeast have experienced significant outages and that these outages occur because of the age of the plants—an average of about 30 years—and the way they have been operated.[51] If these hydropower assets were to be sold without reducing the current backlog of necessary maintenance, bids would be lower. However, a 1995 World Bank review of international experience with divestitures found that in preparing a government enterprise for divestiture, a government should generally refrain from making new investments to expand or improve that enterprise because any increase in sales proceeds is not likely to exceed the value of those investments. DOE's Power Marketing Liaison Office noted that the statement of the World Bank should not be interpreted to imply that federal facilities should be allowed to decay without proper maintenance.

The Specific Sales Mechanism and Process Need to Be Determined

The objectives underlying a divestiture help determine the most appropriate sales method. For example, if a divestiture is largely motivated by fiscal considerations, an appropriate sales mechanism would involve some form of competitive bidding and tend to place few restrictions on the number or identity of bidders.[52] For example, the Congress, in the 1996 National Defense Authorization Act, directed DOE to sell its Naval Petroleum Reserve No. 1 (Elk Hills) by February 1998 and to do so in a manner that would obtain the maximum proceeds to the government.[53] The government has been producing and selling oil and gas from the field for the past 20 years. According to DOE, the reserve's sale is part of an effort to remove the federal government from nonfederal functions. In October 1997, DOE announced that it had executed agreements preparing for the reserve's sale for $3.65 billion in cash as a result of a competition designed to allow all qualified bidders to compete. Before the final selection, DOE had contacted more than 200 companies and received 22 bona fide offers, according to DOE. This sale, which was finalized on February 5, 1998, is the largest divestiture in U.S. government history,

[51]GAO/T-RCED-96-180.

[52]In general, because bids would be likely to increase with more bidders, restrictions on the number of bidders would be likely to lead to smaller sales proceeds. A World Bank survey of international experiences with divestitures indicates that open bidding among competitors is preferable to sales that rely on negotiations with selected bidders because competitive bidding offers less opportunity for favored buyers to receive special treatment at the taxpayers' expense.

[53]An administration proposal to corporatize and sell the reserve in fiscal year 1996 is discussed in Naval Petroleum Reserve: Opportunities Exist to Enhance Its Value to the Taxpayer (GAO/T-RCED-95-136, Mar. 22, 1995).

according to DOE. In general, we have supported the principle that the federal government should receive full market value in selling its assets.[54] Alternatively, if the major motivation of a divestiture is to transfer operations to the private sector, the government could choose to negotiate a sales price with a selected buyer.

In practice, the size of the assets to be sold, in terms of value and scale of enterprise, has influenced the type of sales process used. Trade sales and public stock offerings are general processes; trade sales are used more often to sell smaller enterprises or assets and public offerings to sell larger ones. Sales can be organized using competitive bidding methods or negotiations with either type of sale. A brief description of these processes follows:

- "Trade sales" draw on the idea that an existing set of businesses competing in the relevant line of business (or trade) are likely to offer more and higher bids for the assets. Three key attributes of the PMAS and the electricity industry may lend themselves to a trade sale: (1) the PMAS and related hydropower assets are part of an established industry with capital market connections experienced in the valuation, grouping, and sale of electricity-generating assets; (2) sales of significant electricity-generating assets are not unusual; (3) several bidders are likely for at least large portions of the PMAS and their related assets, depending on how those assets are grouped for sale. A trade sale can be a negotiated sales process between the government and a buyer or can be accomplished using an auction to determine both the sales price of the assets as well as buyers.
- Stock offerings have been used domestically, most recently in the sale of Conrail in 1987, as well as internationally to divest large public enterprises. This method of sale would most likely require creating a government corporation or corporations out of the PMAS and their associated assets. Some of these assets could be grouped for sale, and some could be excluded from the sale, depending on the policy trade-offs discussed. In the case of some federal water projects, for example, the government could decide to retain control of the dam and reservoir to satisfy increasingly significant restrictions on the use of water because of concerns about the environment or endangered species. The stock of the government corporation would be subsequently sold through standard financial market methods, such as a private placement through

[54]See Lessons Learned About Evaluations of Federal Asset Sales Proposals (GAO/T-RCED-89-70, Sept. 26, 1989).

negotiations between particular investors and the government or through a sale to the general public by using competitive bidding.

In cases where auction methods may be used to sell government assets, recent government experience indicates the importance of carefully choosing the specific format for an auction. That is, a policy decision to choose a competitive auction format requires making many subsequent decisions to define the specific rules leading to an appropriate operational auction. For example, the Federal Communications Commission chose to auction the leases of electromagnetic spectrum licenses for use in mobile communications. While generating a large amount of revenue was a less important objective than achieving an efficient geographic allocation of spectrum licenses to communications firms, the auctions generated more revenue than some potential bidders had predicted, according to auction analysts. In large part, in structuring these auctions, the government carefully considered the auction format and the identification of particular problematic features of auctions of similar assets in other nations.

Most domestic and international divestitures have relied on private capital market firms as consultants and managers because of their frequent experience with complicated and high-valued transactions governing the transfer of assets in the private sector. Particularly in the case of public offerings but also for trade sales, the government would be likely to incur substantial costs to prepare its assets for sale or to pay for services performed by its financial advisers. For example, in the sale of Conrail, the government employed a variety of financial advisers and a prominent law firm with expertise in a variety of fields, including tax and employment law. Also, legislation authorizing the sale of DOE's Elk Hills Naval Petroleum Reserve required DOE to use an investment adviser to administer the sale.

If the government's objective is to perpetuate the social and public policy compacts concerning public power, it could transfer or sell its hydropower assets to the preference customers. The assets could be sold free of the debt associated with them. Although such a transaction would provide some revenue to the Treasury, it would probably provide less of a return to the Treasury than a sale to parties that would be willing to pay the highest bid possible for the assets. A debt-free transfer is also harmful to the Treasury because it would incur the debt associated with the hydropower assets, including perhaps any associated debt previously repaid by power revenues—for example, the federal investment in irrigation projects beyond the ability of irrigators to repay. A variation of this suboption is contained in a bill now before House committees. According to the bill's sponsor, this proposal is designed to avoid the fight over elimination of preference by issuing warrants entitling the existing preference customers to purchase, by a pre-set date and at a stipulated price, a fixed number of shares (based on recent electricity purchases) in the PMA from which they purchase power. The stipulated price would be set somewhat below the expected market price value of the shares. The warrants would be fully negotiable so that the preference customers could sell them if they so chose. The actual sale of the shares would be made to individuals, which could be IOUs or investment bankers, holding the warrants on the specified day of sale.

Impact of a Divestiture on Preference Customers' Rates Should Be Considered

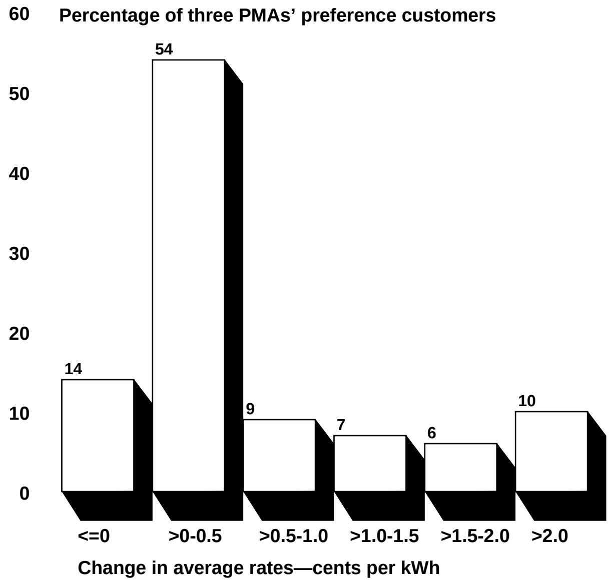
How a divestiture could affect preference customers' rates needs to be considered. Some of Southeastern's, Southwestern's, and Western's customers are concerned that a sale would significantly raise their rates. From 1990 through 1995, the three PMAs received less than 2 cents per kWh for their power—at least 40 percent less than what the nonfederal utilities received per kWh during the same period. However, proponents of divestiture contend that competition in the wholesale market would be likely to moderate rate increases. For example, representatives of the Edison Electric Institute (the trade association for IOUs) maintain that because the wholesale market is competitive, very few preference customers will lack access to alternate power suppliers following a divestiture. They believe that, after a PMA is divested, some preference customers who relied heavily on that PMA will be able to purchase power from independent power producers, energy brokers, or energy marketers at competitive rates. In addition, as we noted earlier in this report, many states are moving toward deregulating both wholesale and retail markets.

Representatives of PMAs and their customers believe that having access to alternate supplies of electricity is not enough. They note that even in cases in which preference customers may buy most of their electricity from alternate sources, these customers often rely on the PMA for power during hours of peak demand, particularly in areas where Southeastern and Southwestern sell power. Having access to inexpensive power during times of peak demand is important to these customers because, typically, power sold to meet this demand is more expensive than power sold at other times. In response, Edison Electric Institute officials maintain that preference customers will be able to purchase power even during peak periods at competitive prices.

To address these concerns, we estimated how much preference customers' rates might increase if the PMAs were divested. We examined only the potential rate impacts of divesting the PMAs and excluded other factors that are currently volatile and difficult to project. In our analysis, we assumed, among other things, that (1) immediately after a divestiture, the buyer of the PMA would raise each preference customer's rates to the level the customer paid for non-PMA power in 1995 and (2) the preference customers do not change the quantity of electricity they purchased in 1995. Because of a lack of data, we did not assess how increasing competition in the wholesale market may affect the rate changes from divestiture. Also, we did not project whether the emergence of competition in retail markets would affect rates in the wholesale market. It is important to note that our methodology yields conservative results. If prices for wholesale power decline in the future, as many industry analysts believe they will, preference customers' actual rate changes from divestiture will be smaller than our estimates.

Our analysis shows that most preference customers will experience relatively small rate increases after a divestiture of the PMAs. As shown in figure 3.1, we estimate that more than two-thirds of preference customers may see rate increases of 25 percent or less, or up to 0.5 cents per kWh. If the preference customers passed these costs directly on to their end-users, the average residential end-users' electricity bills would increase by no more than $4.17 per month. However, we also estimate that some preference customers, mainly those that purchase a large portion of their power from the PMA, may see their rates increase more. About 13 percent of preference customers may see rate increases that exceed 75 percent. Expressed in kWh, about 16 percent of preference customers may see their rates increase by more than 1.5 cents per kWh. If costs are passed directly, the average residential end-users served by about 25 percent of preference customers would see their electricity bills increase by more than $8.33 per month.

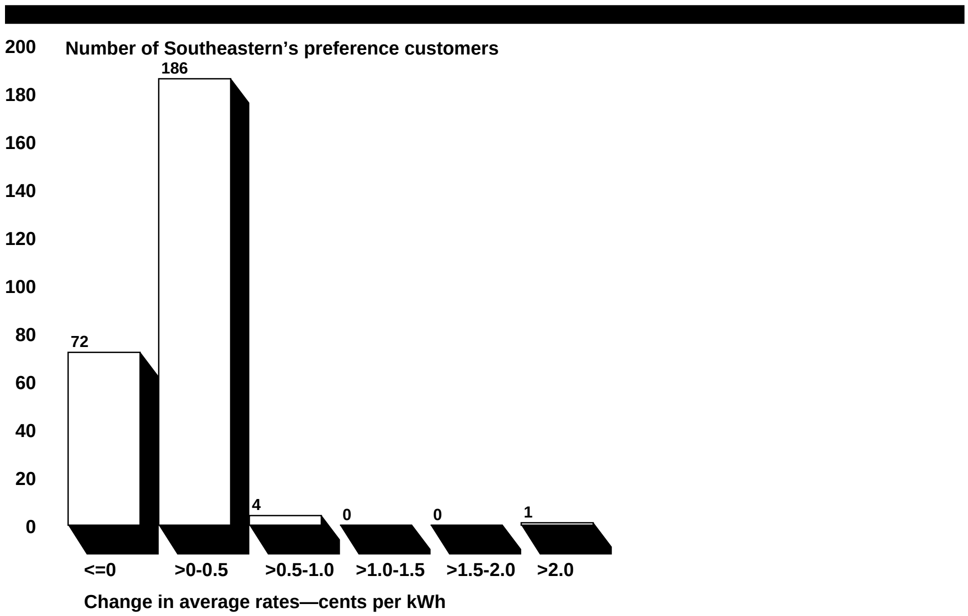
Figure 3.1: Projected Rate Changes After a Divestiture for the Preference Customers of Southeastern, Southwestern, and Western



Source: GAO's analysis of data provided by EIA, Southeastern, Southwestern, and Western.

Preference customers who currently purchase a small portion of their total power from Southeastern, Southwestern, or Western generally may experience smaller rate increases after a divestiture. For example, in fiscal year 1995, 99 percent of Southeastern's preference customers received less than a quarter of their power from the PMA. Correspondingly, as illustrated in figure 3.2, we calculated that almost all (98 percent) of Southeastern's preference customers may experience rate increases of 0.5 cents per kWh or less, and 99 percent would see their rates increase by one-quarter or less. Moreover, we estimated that about 27 percent (or 72) of these customers may see their rates decline if they purchased all of their power at 1995 wholesale market rates. Some of these customers currently may have access to less expensive power; however, for various reasons, these customers have opted not to buy from these sources.[55]

Figure 3.2: Post-Divestiture Rate Changes for Southeastern's Preference Customers



Source: GAO's analysis of data provided by EIA and Southeastern.

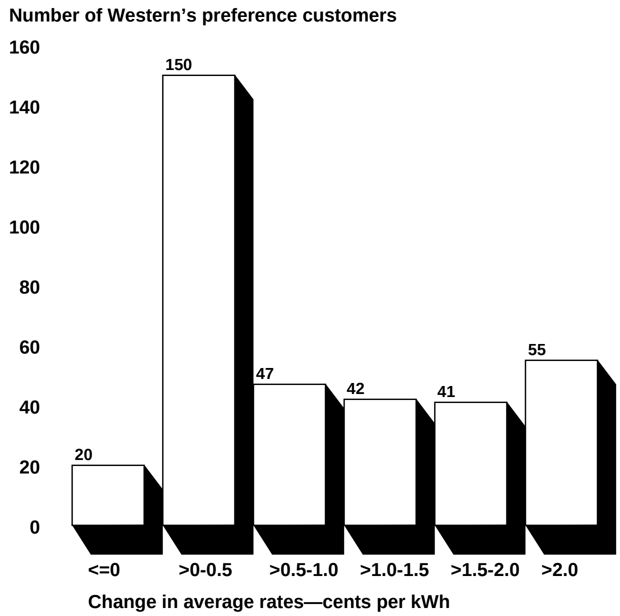
In contrast, preference customers who currently purchase most or all of their power from the PMA may experience much greater rate increases. For example, in 1995, about 38 percent of Western's preference customers purchased more than half of their electricity from the PMA. As shown in figure 3.3, we estimated that about one-fifth of Western's customers may

[55]The customers that may experience a rate decrease are those that are currently purchasing power from the PMA at rates that are above the market price. In theory, in these situations, after a divestiture, the rate for power formerly provided by the PMA would decrease to the prevailing market rate, and these customers would experience an overall decrease in the cost of their power. However, according to PMA customers, this analysis does not consider the fact that the PMA's power, in many cases, satisfies demand during peak periods. According to PMA customers, in this niche, the PMAs' power is often less expensive than peaking power offered by other sources. Some PMA customers have built their own generating capacity based on buying a PMA's power and using it for peaking purposes. They maintain that it would be costly and difficult to replace the power supplied by the PMAs because it is unlikely that less expensive sources of power could be found for peaking purposes and that they may be forced to build new types of baseload capacity if their resource requirements change. They also do not believe that a buyer of the PMA would necessarily decrease the price of the PMA's power to match overall power rates but would be more likely to increase the price to match that of power generated from power plants used to serve peak demand.

see their rates increase by more than 75 percent. About 27 percent of preference customers may see rate increases greater than 1.5 cents per kWh. If preference customers pass the higher rates on to those they serve, the average residential end-users served by about 16 percent of Western's preference customers may see their electricity bills increase by at least $16.67 per month.

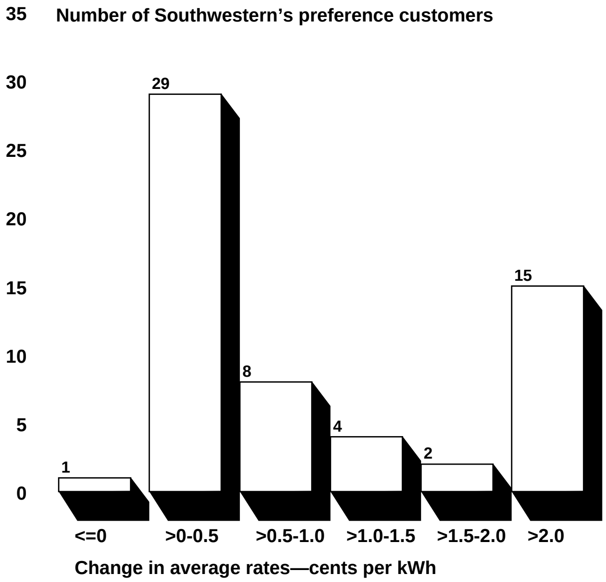
Similarly, almost one-third of Southwestern's preference customers purchase more than 75 percent of their electricity from the PMA. As shown in figure 3.4, although most of Southwestern's preference customers will experience relatively small rate changes, about 25 percent may see their rates more than double. If these preference customers pass these increases on to those they serve, the average residential end-users may see their rates increase by at least $16.67 per month.

Figure 3.3: Post-Divestiture Rate Changes for Western's Preference Customers



Source: GAO's analysis of data provided by EIA and Western.

Figure 3.4: Post-Divestiture Rate Changes for Southwestern's Preference Customers



Source: GAO's analysis of data provided by EIA and Southwestern.

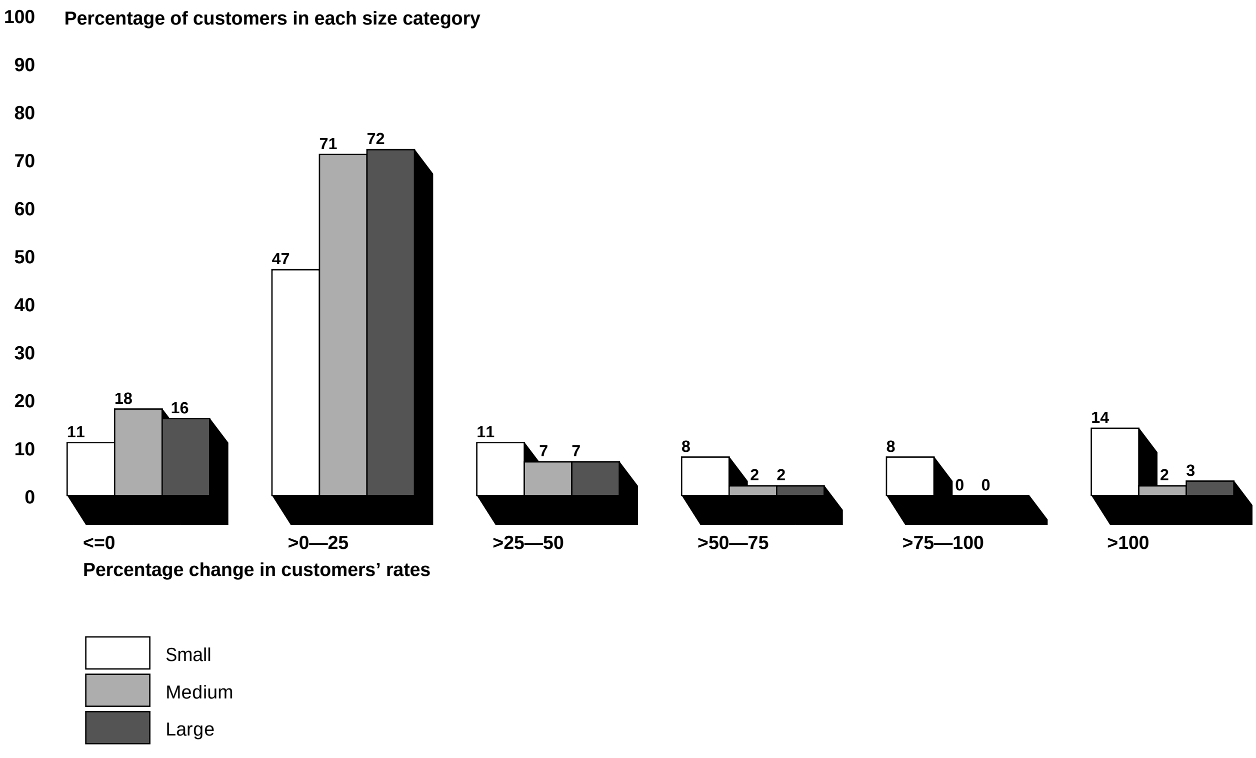
It is important to remember that, although some preference customers may initially experience significant rate increases, government may mitigate these rate increases through various mechanisms, such as rate caps. In addition, these customers currently pay rates that, on average, are 40 to 50 percent below what neighboring utilities pay that do not have access to PMA power. After the divestiture, these preference customers will be paying the same market rates as those utilities.

Finally, smaller-sized preference customers may experience larger rate increases after divestiture.[56] As illustrated in figure 3.5, we estimated that about one-fifth of Southeastern's, Southwestern's, and Western's small preference customers will experience rate increases exceeding 75 percent. About 30 percent of small customers will see their rates rise by more than 1.5 cents per kWh. In contrast, 2 percent of medium-sized preference

[56]We measured size by the number of MWh that each preference customer delivered to its end-users from all sources in calendar year 1995. We categorized size as follows: "small" = 0 to 100,000 MWh; "medium" = more than 100,000 to 500,000 MWh; "large" = more than 500,000 MWh. We discussed these categories with the American Public Power Association, an association of publicly owned utilities, and the National Rural Electric Cooperatives Association, an association of consumer-owned rural electrical systems.

customers and 3 percent of large preference customers may see rate increases exceeding 75 percent. However, in all three size categories, a majority of preference customers may experience rate increases of 25 percent or less or 0.5 cents per kWh or less. We believe smaller customers may experience larger rate increases after divestiture because they generally purchase a larger portion of their power from the PMAS than medium-sized and large preference customers.

Figure 3.5: Projected Rate Changes After a Divestiture for Southeastern's, Southwestern's, and Western's Preference Customers, by Size of Customer



Source: GAO's analysis of data provided by EIA, Southeastern, Southwestern, and Western.

Results of GAO's Prior Work on the Tennessee Valley Authority

The Tennessee Valley Authority (TVA) had $27.9 billion of debt and $6.3 billion of deferred assets on September 30, 1996. In reports we issued in 1995[1] and 1997,[2] we concluded that TVA's high fixed costs and deferred assets may hinder its ability to compete if TVA is required to participate in a deregulated market. In a competitive market, where wholesale prices are expected to decrease, TVA's high fixed costs and deferred assets make it reasonably possible that the federal government would incur future losses.[3] However, in recent years, TVA, the nation's largest electric power generator, has taken several actions to improve its competitiveness. In addition to reducing its labor force, refinancing its debt, and bringing two deferred nuclear units back into service, TVA has recently increased its rates as part of its efforts to reduce its debt by 50 percent by fiscal year 2007. TVA's service area is protected from competition under federal law; as long as this is the case, the risk that TVA will cause the federal government to incur losses is remote.

Background

TVA was established by the Tennessee Valley Authority Act of 1933 as a multipurpose, independent, federal corporation. The act created TVA to improve the quality of life in the Tennessee River Valley by improving navigation, promoting regional agricultural and economic development, and controlling the flood waters of the Tennessee River. As part of TVA's efforts to fulfill these objectives, it erected dams and hydropower facilities on the Tennessee River and its tributaries. TVA also developed fertilizers, taught farmers how to improve crop yields, and helped replant forests, control forest fires, and improve habitats for wildlife and fish.

To meet the growing need for electric power during World War II, TVA quickly expanded its construction of hydropower plants. By the end of the war, TVA had become the nation's largest electricity supplier. However, the demand for electricity in the region outpaced TVA's capacity. To secure funding for the construction of coal-fired power plants, TVA sought the authority to issue bonds. The Congress passed legislation in 1959 that gave TVA the authority to issue bonds and required TVA's power program to be

[1]Tennessee Valley Authority: Financial Problems Raise Questions About Long-term Viability (GAO/AIMD/RCED-95-134, Aug. 17, 1995).

[2]Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses: Volume 1 (GAO/AIMD-97-110, Sept. 19, 1997).

[3]We based our discussion of the risk of nonrecovery involved on the Statement of Federal Financial Accounting Standard No. 5, Accounting for Liabilities of the Federal Government. The Standard states that if the chance a contingent loss will occur is more likely than not, the risk of loss is "probable"; if the chance is more than remote but less than probable, it is "reasonably possible"; if the chance is slight, it is "remote."

self-financed.[4] TVA's debt limit is set by the Congress and was established at $750 million in 1959.[5]

The 1960s was a period of unprecedented economic growth in the Tennessee Valley. Expecting the Valley's electric power needs to continue to grow, TVA decided to add nuclear power plants to its power system. In 1996, TVA had a dependable generating capacity of over 28,000 megawatts (MW). The system primarily consists of 113 hydroelectric units, 59 coal-fired units, 48 combustion turbines, and 5 operating nuclear units.

TVA's power program generated $5.7 billion in revenues in fiscal year 1996. As of January 1998, TVA sells power at wholesale rates to 159 municipal and cooperative distributors and to a number of directly served large industrial customers and federal agencies. TVA's sales to its distributors in fiscal year 1996 constituted approximately $5.0 billion (or 88 percent) of TVA's total revenue for the year. Most of the power contracts between TVA and its distributors contain a 20-year term that automatically renews each year and require that the distributors give TVA at least a 10-year notice of cancellation. The distributors, in turn, sell the power to nearly 8 million people in an 80,000-square-mile area covering Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia.

TVA's Financial Condition Reduces Its Flexibility and Ability to Compete in the Future

As we discussed in reports issued in 1995 and 1997,[6] TVA's high debt, related financing costs, and deferred assets would limit the agency's flexibility to respond to competitive pressures if it were no longer protected from competition. TVA has operated with little oversight in the past, and investments in its construction program for nuclear power plants constitute most of its debt and all of its deferred assets.

Designed as a Wholly Owned Government Corporation, TVA Operates With Little Outside Oversight

TVA's authorizing legislation allows it to operate with a high degree of independence. The TVA Act of 1933 did not subject TVA to the regulatory and oversight requirements that must be satisfied by commercial electric utilities. For example, unlike other utilities, TVA's power rates and power resource decisions are not subject to review and approval by state public utility commissions or the Federal Energy Regulatory Commission (FERC).

[4]TVA's activities are divided into two types—the power program and the nonpower programs. The nonpower programs, such as flood control, navigation, and water resources, are primarily funded through federal appropriations and user fees. The nonpower programs received $106 million in funding for fiscal year 1997 and operate primarily within the 41,000-square-mile Tennessee River watershed.

[5]Since then, the Congress has raised the debt limit to $30 billion.

[6]GAO/AIMD/RCED-95-134 and GAO/AIMD-97-110.

Instead, all authority over TVA's operations is vested in TVA's three-member board of directors, including the sole authority to set wholesale power rates and approve the retail rates charged by TVA's distributors. The three board members are full-time TVA employees. They are appointed by the President, with the advice and consent of the Senate, and serve 9-year, overlapping terms of office. The President designates one member as the chairman. In addition, the Congress has little oversight over the funding of TVA's power program, which is self-financed through power revenues and bond issuances and does not require federal appropriations. TVA's power funds are maintained in a revolving fund called the TVA Fund.

The issue of TVA's oversight has been examined several times in the past. For example, in a 1982 report, we pointed to a growing concern with TVA's activities and identified options for improving oversight and accountability.[7] These options included periodic congressional oversight hearings and placing the TVA rate-setting process under FERC. In a 1983 report, we discussed our concerns about TVA's management and concluded that the issue of the adequacy of TVA's oversight needed greater attention.[8] In a 1987 report entitled "TVA—A Path to Recovery," the Southern States Energy Board concluded that "additional mechanisms are needed to ensure that TVA is accountable for its actions to its ratepayers, Congress, and the American public."[9] The report further stated that:

> "There must be a fundamental change in TVA's structure to effectively respond to today's challenges and meet the necessary standards of accountability. A larger Board should be established, comprised of part-time directors who would be responsible for policy-making and oversight of TVA's management."

In 1997, TVA's oversight was a topic of debate in the Congress. The possibility of deregulating electric utilities in the future led one Representative to propose the formation of an independent regional commission to make recommendations to the President and the Congress on a strategy for TVA's future in a deregulated environment. Another Congressman has expressed interest in the expansion of TVA's current board of directors. In October 1997, a bill was introduced in the Senate to expand TVA's board from three full-time members to nine part-time members, each having a strong background in corporate management or

[7] Tennessee Valley Authority—Options for Oversight (GAO/EMD-82-54, Mar. 19, 1982).

[8] Triennial Assessment of the Tennessee Valley Authority—Fiscal Years 1980-1982 (GAO/RCED-83-123, Apr. 15, 1983).

[9] The Southern States Energy Board was comprised of government and industry experts with diverse experience in energy operations, management, and regulation.

strategic decision-making. Under this proposal, the expanded board would establish long-range goals and policies for TVA, but it would leave the day-to-day management to an independent chief executive officer. According to the bill's sponsor, such a management structure could help TVA "avoid the type of decisions and missteps that have saddled TVA with more than $27 billion in debt over the years" and "can help this important agency face the upcoming dramatic changes in the electric utilities industry as effectively and efficiently as possible." As of November 30, 1997, neither proposal had been implemented.

Investment in Nuclear Program Increased Debt

TVA made its commitment to nuclear power in the late 1960s and early 1970s, when power sales were growing at a steady rate and were expected to double every 10 years. By 1970, TVA customers used nearly twice as much electricity as the national average. At that time, TVA was experiencing an annual growth rate of about 8 percent in demand for electricity, and its forecasts through the mid-1970s were showing continued high growth in demand.

In 1966, TVA announced plans to construct a total of 17 nuclear units at seven sites in Alabama, Mississippi, and Tennessee to satisfy its forecast demand. However, instead of increasing, electricity consumption declined in the mid-1970s following the 1973 energy crisis and again in the late 1970s with higher energy costs and lower economic growth. In addition, because of the Three Mile Island nuclear accident in 1979, the Nuclear Regulatory Commission (NRC) issued extensive new safety regulations that applied to all nuclear plants. The decreasing demand for electricity, coupled with the increased regulation of nuclear power, caused the electric utility industry to rethink the role that nuclear power would play in meeting the nation's demand for electricity. Most utilities chose to cancel ongoing nuclear construction projects as well as planned nuclear power plants.

After reassessing its electricity demand forecasts using a more sophisticated methodology, TVA began to scale back its nuclear plans by canceling 8 of its 17 planned nuclear units in 1982 and 1984. The almost $5 billion invested in these eight units was written off over 10 years and recovered through rates. TVA's remaining nine nuclear units have had a long history of operating and construction problems. As of September 30, 1996, TVA had five nuclear units in operation. The two most recent additions to TVA's nuclear power resources are Browns Ferry 3, which was returned to service in November 1995, and Watts Bar 1, which began commercial operation in May 1996. Browns Ferry 3 began operations in 1977 but was shut down in 1985 because of repeated operational and maintenance errors. Watts Bar 1 had been under construction for about 23 years and had never been operated. Construction at these two nuclear units involved years of schedule delays and cost overruns. For example, TVA certified to the NRC that Watts Bar 1 was qualified for an operating license in 1985, but the Commission did not grant one because of over 5,000 unresolved concerns about construction deficiencies and management practices at the facility that were reported by TVA employees. According to TVA, the total costs associated with the completion of Watts Bar 1 and Browns Ferry 3 were about $6.9 billion and $1.4 billion, respectively, as of September 30, 1996.

Of TVA's four remaining nuclear units, Bellefonte 1 and 2 and Watts Bar 2, were not completed and have been kept in a "mothballed" status. In December 1994, TVA determined that it would not, by itself, complete Bellefonte 1 and 2 or Watts Bar 2 as nuclear units. TVA has been considering the possible conversion of the Bellefonte plant to a combined cycle plant utilizing another fuel source, such as gas or coal, and/or the formation of a joint venture with a partner for completion of the plant. TVA also concluded that Watts Bar 2 should remain in deferred status until TVA completes the Bellefonte study. TVA has already invested about $6.3 billion in these three units. The remaining "mothballed" nuclear unit, Browns Ferry 1, has been shut down since 1985 because of ineffective management and technical difficulties. While TVA's investment in Browns Ferry 1 totals approximately $86 million, it "will continue to remain in an inoperative status until its ultimate disposition is determined," according to TVA's fiscal year 1996 annual report.

Despite the past problems TVA experienced with its nuclear program, TVA has recently reported positive developments concerning its nuclear units. In 1996, the NRC conducted performance reviews of Watts Bar 1 and the two operating units at Browns Ferry. The NRC gave either "good" or "superior" rankings to the three units in the four functional areas of engineering, maintenance, operations, and plant support. Nevertheless, while five of TVA's nine nuclear units are operational, TVA's investment in its nuclear power program has left it in a difficult financial condition that may limit its ability to compete in a deregulated market.

TVA's Financial Condition May Limit Its Flexibility

Primarily as a result of TVA's investment in nuclear power, TVA's outstanding debt grew from $15 billion at the end of fiscal year 1983 to almost $28 billion at the end of fiscal year 1996. The outstanding debt consists primarily of about $3.2 billion in direct federal borrowing from the Federal Financing Bank and about $24.1 billion in publicly issued TVA debt, which is not explicitly guaranteed by the federal government. In addition, TVA is also required to repay funds appropriated to it prior to its becoming self-funding in 1959—approximately $600 million as of September 30, 1996.[10]

As a result of its debt, TVA's total interest expense in fiscal year 1996 was about $2 billion, representing about 35 percent of TVA's operating revenue, according to TVA's annual report. TVA's ratio of financing costs to revenue is now more than twice as high as the average financing costs for neighboring utilities. In addition, TVA's ratio of fixed financing costs to revenue is almost five times higher than the average of its neighboring investor-owned utilities (IOUs). The high debt and high financing costs allow TVA less flexibility to reduce costs and, hence, to lower its rates to meet competitors' prices.

In addition, in September 1997 we reported that TVA deferred about $6.3 billion in capital costs for its nonproducing nuclear assets to future years rather than currently including them among the costs being recovered from ratepayers.[11] TVA considers these assets—the Bellefonte 1 and 2 and Watts Bar 2 nuclear units—to be construction work-in-progress. TVA has concluded that the recovery of the costs of these assets will not begin until the units are either completed and placed into service or canceled. TVA charges its ratepayers for the costs of its property, plant, and equipment and canceled plants through depreciation and amortization expenses. TVA is required by law to set rates so that power revenues cover all operating expenses, including depreciation and amortization. While the annual interest expense from the debt associated with these assets is included in current rates, TVA is not currently depreciating or amortizing its nonproducing nuclear assets. TVA has stated that it will not, by itself, complete Bellefonte 1 and 2 or Watts Bar 2 as nuclear units, and it has not conducted any construction work on these units for approximately 9 years. As we reported previously, we believe that the $6.3 billion in costs associated with these three units does not represent viable construction projects.[12] These are the only deferred nuclear units in the United States.

[10]TVA refers to this debt as "appropriated investment"; however, this amount does not count toward TVA's $30 billion debt limit. TVA must repay all but $258.3 million of the appropriations that were used for capital investments, plus interest.

[11]GAO/AIMD-97-110.

[12]GAO/AIMD-97-110.

In our judgment, it is no longer reasonable for these costs to be deferred from current revenue requirements. How much TVA's revenue requirements will increase depends on when and over what period of time TVA begins recovering its investment in its nonproducing nuclear assets. By not including the costs of its deferred nuclear units in rates and using the cash to pay off debt in prior years, TVA has allowed its high fixed and deferred costs to put upward pressure on its rates at a time when competitors' power rates are expected to be falling.

Electricity Industry Is Becoming More Competitive

As previously mentioned, IOUS have historically maintained exclusive service areas in return for providing electric service to all customers in their areas. Through their electricity rates, the IOUS generally recoup the costs to build new generating plants and to operate the power system plus a regulated return. In 1959, the Congress legislatively defined TVA's service territory. However, recent changes in the electricity industry are pushing utilities closer to a competitive market, and utilities have been forced to adopt a more competitive strategy to survive.

The Energy Policy Act of 1992 promoted increased competition in the electricity market. The act encouraged open transmission of electricity by allowing wholesale electricity customers, such as municipal distributors, to purchase electricity from any supplier, even if that power had to be transmitted over lines owned by another utility. In addition, bills have been introduced in various House and Senate committees to promote or mandate retail electricity competition, and several states are actively implementing retail competition. State regulators hope that industrial, commercial, and, ultimately, residential consumers will be able to choose their power supplier.

In the light of the recent push toward deregulation and competition, utilities have begun to adopt new strategies to compete. Some are acquiring or merging with other utilities in order to better respond to market changes. Others are investing in different industries, such as home security and telecommunications. Utilities are also restructuring themselves and decreasing their operating costs through reorganizations and layoffs. Utilities have implemented these and other strategies in response to the uncertainties about the future of the electricity markets.

While the Energy Policy Act exempted TVA from the act's transmission-related requirements, thus preventing competitors from using TVA's transmission system to sell power to customers inside TVA's service area, some of TVA's customers have recently expressed interest in buying power from other sources, to the point of wanting to leave TVA's power system altogether. For example:

- In December 1993, the Four-County Electric Power Association of Columbus, Mississippi, announced that it was canceling its contract with TVA, effective in December 2003. Four-County officials said that a study they commissioned indicated that TVA's wholesale rates may increase by 30 percent over a 10-year period. By buying power from sources other than TVA, Four-County believed it could reduce its power costs by about 25 percent. TVA threatened to cancel plans to construct a lignite-burning power plant in Four-County's region if it did not withdraw its cancellation notice. In May 1996, Four-County withdrew the notice and agreed not to give a 10-year cancellation notice for the next 5 years.
- In Virginia, the Bristol Utilities Board left the TVA system for Cinergy Corp., effective January 1, 1998. Cinergy offered Bristol firm wholesale power at 2.59 cents per kWh for 7 years—40 percent less than TVA's wholesale rate of 4.3 cents per kWh. According to its general manager, Bristol would save $70 million over 7 years. Bristol, which is on the border of TVA's service area, has the ability to pursue the agreement with Cinergy because it does not have a long-term contract with TVA. Bristol also received a unique exemption in the Energy Policy Act of 1992 that allows other utilities to transmit electricity to Bristol over TVA's power lines. While Cinergy may have offered this power to Bristol at marginal rates, this is the type of competitive situation that TVA may face regularly if it loses its current protection from competition. TVA is attempting to recover stranded investment costs from Bristol.
- In May 1997, the board members of the Paducah Power System in Kentucky voted to give TVA a 10-year notice of intent to cancel Paducah's contract with TVA. The board had been presented with at least one study showing that Paducah could buy power from other sources for 10 to 15 percent less than the amount that they were paying TVA. The proposed change must be approved by the Paducah City Council.
- The five largest distributors in TVA's system—Huntsville, Chattanooga, Knoxville, Nashville, and Memphis—have expressed concern about the inflexibility of TVA's power contracts. These utilities, which account for more than one-third of TVA's distributor power sales, hired a consultant to help develop proposals to present to TVA. These distributors are interested in contract flexibility through the negotiation of shorter contracts and favor the ability to purchase power from outside sources. These large distributors anticipate using their leverage to compel TVA to renegotiate their power contracts.

Federal Government Faces Different Degrees of Risk With TVA

Despite the industry's push toward competition and pressure from some of TVA's customers, several factors protect TVA from competition, making the risk of loss to the federal government remote in the short term. The long-term risk, however, appears to be greater.

The federal government's financial exposure from TVA is nearly $28 billion because of its direct and indirect financial involvement. The risk that TVA will cause the federal government to incur losses is remote as long as TVA retains a position in its service area that is protected from competition. However, if TVA loses its protected position and is required to compete at a time when wholesale prices are expected to be falling, its high financing costs and deferred assets make it reasonably possible that the federal government could incur losses in the future. The federal government's direct financial involvement with TVA consisted of about $600 million of appropriated debt[13] and about $3.2 billion in Federal Financing Bank debt, as of September 30, 1996. If TVA fails to make future payments on its outstanding appropriated and Federal Financing Bank debt, the federal government will incur a loss. The government could also incur a loss because of its indirect financial involvement, which consists of TVA's public debt of about $24.1 billion, as of September 30, 1996, should it have to absorb unreimbursed costs from any actions it would take to prevent default on the debt service requirements.

TVA's Protection From Competition Makes Federal Government's Short-Term Risk Remote

Two major factors protect TVA from competition and allow it to operate in a manner similar to a traditionally regulated electric utility monopoly. First, in nearly all instances, TVA's contracts with its 159 distributors require the distributors to give at least a 10-year notice before they can switch to another power supplier.[14] Second, TVA is exempt from the transmission-related provisions of the Energy Policy Act of 1992. This exemption prevents other utilities from using TVA's transmission system to sell power to customers inside TVA's service area.

TVA's wholesale contracts with its distributors are generally long-term contracts that ensure TVA a relatively stable customer base and cash flow. These contracts represented about 83 percent of TVA's load as of September 30, 1996. Most of the wholesale power contracts between TVA

[13]TVA's appropriated debt consists of appropriations that were primarily used to construct TVA's hydroelectric and fossil plants, transmission system, and other general assets of the power program. TVA must make annual principal payments (currently $20 million) to the Treasury from net power proceeds plus a market rate of return on the balance of this debt.

[14]Some wholesale power contracts between TVA and wholesale customers require a 15-year notice of cancellation.

and its distributors contain a 20-year term that automatically renews each year (referred to as the "evergreen" provision) and require that the distributors give TVA at least a 10-year notice of cancellation. This notice provision effectively locks the distributors into purchasing power from TVA since obtaining price quotes for power to be supplied 10 to 15 years into the future is generally not feasible. All of the power contracts between TVA and its distributors are "full requirements" contracts, which require the distributors to purchase all of their electric power from TVA.

TVA is further insulated from competition by a specific exemption from the transmission-related provisions of the Energy Policy Act of 1992. Under the act, FERC can compel a utility to transmit electricity generated by another utility into its service area for sale to wholesale customers. The act acknowledged that TVA is legally prohibited from selling power outside its legislatively mandated service area and therefore exempts TVA from having to transmit power from neighboring utilities to wholesale customers within TVA's service area. While TVA is authorized to allow other utilities to use its transmission lines to transmit power through its service area to other utilities, it is not required to allow other utilities to sell power to customers within TVA's service area.

Risk of Loss Is Reasonably Possible If TVA's Protection From Competition Ends

According to our discussions with industry experts and TVA officials, it appears unlikely that TVA will be allowed to maintain its current regulated monopoly-type structure indefinitely: At some future point, TVA will have to compete with other utilities. In a competitive environment, utilities that have low costs and the flexibility to adjust their rates to meet those being offered by other utilities are expected to be the most successful. We believe TVA's substantial fixed costs and deferred assets will limit TVA's flexibility to continue to offer competitive rates and may affect its ability to recover all costs when competitors' prices are being driven down.

TVA has chosen to defer costs from its substantial nuclear investment to future years rather than include them in the current costs being recovered from ratepayers. As a result, TVA had accumulated about $28 billion of debt, as of September 30, 1996, which resulted in almost $2 billion in interest expense in fiscal year 1996. The recovery of these deferred assets is most likely to be scheduled at a time when wholesale power rates are expected to be falling.

In a previous report, we compared the financial ratios of TVA and neighboring IOUs that indicate the flexibility of these entities.[15] We also computed ratios that compare the magnitude of TVA's deferral of costs with those of its most likely competitors. We found that TVA's ratios of financing costs to revenue greatly exceed the ratios of its neighboring utilities, indicating that TVA has less flexibility to lower prices to meet competition. In addition, the calculation of deferred asset ratios indicated that while TVA has deferred substantial costs, its potential competitors have written down the assets they deem to be uneconomical at a much faster rate, allowing them to recover costs at a much greater pace than TVA and thus giving them greater financial flexibility in the future.

The primary component of TVA's deferred assets is about $6.3 billion in capital costs for its nonproducing nuclear assets—Bellefonte 1 and 2 and Watts Bar 2. In December 1994, TVA determined it would not, by itself, complete Bellefonte 1 and 2 or Watts Bar 2 as nuclear units. However, TVA is studying the potential for converting the Bellefonte facility to a combined cycle plant or forming a joint venture with a partner for completion of the plant. This study was scheduled to be completed by the fall 1997. TVA also concluded, as part of its Integrated Resource Plan, that Watts Bar 2 should remain in deferred status until completion of the Bellefonte study.

We believe that two additional factors could contribute to TVA's future vulnerability to competition: the concentration of TVA's sales to its five largest distributors and the number of TVA's customers that are already connected to the transmission lines of other utilities. As previously reported, the five biggest distributors in TVA's system, which accounted for 34 percent of TVA's total sales to distributors in fiscal year 1996, have expressed concerns about their lack of flexibility to purchase power from outside sources. The large distributors hope to use their leverage in order to compel TVA to renegotiate their power contracts. In a competitive environment, TVA would likely have to lower the rates of these distributors or run the risk of losing them as customers, which could be financially crippling to TVA. In addition, 12 other TVA distributors are already interconnected with other utilities. These distributors could get power from other sources after their contracts with TVA expire. The demand from these customers amounts to about 2 percent of TVA's total load. As competition intensifies in the region, TVA could lose distributors to other suppliers using existing and future transmission connections.

[15]GAO/AIMD/RCED-95-134.

Mitigating Factors Reduce the Risk of Loss

Other factors, such as the inherent cost advantages of a federal corporation and an extensive transmission system, mitigate the risk created by TVA's high financing costs and deferred assets. In addition, TVA's management has taken several actions in recent years to reduce TVA's expenses and make it more competitive. Because of these factors and actions, we believe the risk of loss to the federal government is reduced but is still reasonably possible.

TVA Has Inherent Cost Advantages

According to bond-rating agencies, TVA's creditworthiness is based on its links to the federal government. In accordance with the TVA Act, TVA's debt issuances explicitly state on the bond prospectus that the bonds are neither legal obligations of, nor guaranteed by, the federal government. Nevertheless, TVA's bonds are rated by the major bond-rating agencies as if they have a federal guarantee. Without the links to the federal government, we believe that TVA would have a lower bond rating and higher cost of funds.

In addition, as a federal government corporation, TVA is exempt from federal and state income taxes and does not pay various local taxes. While TVA is required to make payments in lieu of taxes to state and local governments of the jurisdictions where power operations are conducted, the base amount TVA is required to pay amounts to only about 5 percent of TVA's gross power revenues (not including sales to other federal agencies).[16] In addition, according to TVA, its distributors are required to pay various state and local taxes, which amounted to about $125 million, or about 2 percent of the total fiscal year 1995 operating revenues of TVA and the distributors. In comparison, IOUs pay about 14 percent of their operating revenues for taxes. In addition, interest income for TVA's bondholders is generally exempt from state income taxes, which further lowers TVA's costs of funds.

Other cost advantages that TVA possesses are its hydropower assets and its preference in purchasing low-cost power from the Southeastern Power Administration (Southeastern). TVA has relatively more hydroelectric power than neighboring utilities. About 11 percent of its power is generated from its 113 hydroelectric units at 29 conventional dams. In comparison, an average of 6 percent of the power from other utilities comes from hydroelectric dams. These established hydroelectric projects are relatively inexpensive and have no associated fuel costs. TVA also

[16] In fiscal year 1996, for example, TVA made $256 million in payments in lieu of taxes to state and local governments.

purchases about 2 percent of its annual power needs from Southeastern. In fiscal year 1996, TVA purchased this power for 0.8 cents per kWh.

TVA's Recent Actions Have Lowered Costs and Increased Revenues

Over the years, TVA has taken several steps to enhance its competitiveness. For example, it canceled a number of its nuclear construction projects in the early 1980s and, more recently, completed the construction of Watts Bar 1 and restarted Browns Ferry 3. TVA also recently announced that it has internally capped its debt limit at about $28 billion and plans to finance its future capital expenditures from operations. In addition, by reducing its workforce from 34,000 in 1988 to 15,308 in June 1997 and refinancing its debt at lower interest rates, TVA has reduced its annual operating costs.

In July 1997, TVA released a 10-year business plan that identifies actions it plans to take to meet the challenges from the restructuring electricity marketplace. The proposed actions address several of the concerns that we raised in our August 1995 report. The plan calls for TVA to

- increase power rates enough to increase annual revenues by about 5.5 percent ($325 million);
- take various actions to reduce its total cost of power by about 16 percent by fiscal year 2007;
- reduce employment levels to 14,275 by September 30, 1997;
- limit annual capital expenditures to $595 million; and
- reduce debt by about 50 percent from $27.9 billion, as of September 30, 1996, to $13.8 billion by fiscal year 2007.

To the extent that TVA is able to use the cash generated from increasing rates, reducing expenses, and capping future capital expenditures to pay down debt, the risk of loss to the federal government is reduced. In addition to these actions, the plan calls for TVA to change the length of the wholesale power contracts with its distributors from a rolling 10-year term to a rolling 5-year term beginning 5 years after the amendment. However, reducing the length of the wholesale contracts with its distributors could increase the risk of loss to the federal government by giving TVA's customers more flexibility to end their contracts with TVA.

Results of GAO's Prior Work on the Rural Utilities Service

In September 1997,[1] GAO found that the Rural Utilities Service (RUS) operates its loan programs at a net cost to the federal government because the annual interest income received from RUS borrowers is substantially less than the government's annual interest expense to provide the funds to borrowers. In addition, in fiscal years 1996 and 1997, RUS wrote off $1.6 billion in electric loans. Moreover, as of September 30, 1996, $10.5 billion of the $32.3 billion total electric portfolio represented loans to borrowers that are bankrupt or otherwise financially stressed. As the electric utility industry moves toward deregulation, it is probable that the federal government will continue to incur substantial losses from financially stressed borrowers and from other borrowers with high production costs and the inability to raise rates because of regulatory and/or market pressures.

RUS, an agency within the Department of Agriculture, provides direct and guaranteed loans primarily to rural electric cooperatives that market power on a wholesale and retail basis. Through RUS, the Department of Agriculture, as the federal government's principal provider of loans to assist the nation's rural areas in developing their utility infrastructure, finances the construction, improvement, and repair of electrical systems. RUS provides credit assistance through direct loans and through repayment guarantees on loans made by other lenders. Since the 1930s, the federal government has provided billions of dollars in direct electricity loans and guarantees on loans made by other lenders primarily to cooperatives that serve rural areas.

RUS' Electricity Loan Programs

Established by the Federal Crop Insurance Reform and the Department of Agriculture Reorganization Act of 1994, RUS administers the electricity programs that were operated by the former Rural Electrification Administration (REA).[2] The Congress created REA in 1935 as part of a coordinated federal effort intended not only to improve living conditions in rural areas, but also to alleviate the high unemployment the nation experienced during the Depression. Because of higher construction and servicing costs, investor-owned electric utilities had not extended service to many sparsely populated areas of the country. To fulfill its mission, REA developed loan programs to assist rural areas in building and operating electric generating facilities as well as wholesale transmission and local

[1] GAO/AIMD-97-110.

[2] RUS also administers the former REA's telecommunications programs and the water and waste disposal programs that were operated by the former Rural Development Administration. In this report, we discuss only the electricity segment of RUS' loan programs.

distribution lines. REA provided credit assistance primarily to cooperatives owned by the consumers. These programs have been successful in helping farms and rural households gain access to electrical service. In 1940, about 25 percent of all households in the nation were without electricity, but about 70 percent of farms did not have electrical service. Today, virtually all households are electrified.

RUS makes direct loans primarily to construct and maintain electricity distribution facilities that provide electricity to rural areas. RUS makes direct loans at below-market interest rates according to law. For these loans, it receives annual appropriations to cover the interest differential. RUS offers direct loans with a 5 percent interest rate to borrowers that serve financially distressed rural areas, as well as municipal rate loans with a maximum 7 percent interest rate to borrowers that meet certain criteria. RUS also provides 100 percent repayment guarantees on loans made by the Federal Financing Bank and commercial lenders to finance the construction, repair, and improvement of electricity generating and transmission assets.

RUS' electricity loans are made primarily to rural electric cooperatives; more than 99 percent of the borrowers with electricity loans are nonprofit cooperatives. These cooperatives are either generation and transmission (G&T) cooperatives or distribution cooperatives. A G&T cooperative is a nonprofit rural electric system whose chief function is to sell electric power on a wholesale basis to its owners, which consist of distribution cooperatives and other G&T cooperatives. A distribution cooperative sells the electricity it buys from a G&T cooperative to its owners, the retail customers. In September 1997, we reported that RUS had 55 G&T borrowers and 782 distribution borrowers located throughout the country with outstanding electricity loans.[3]

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

[3]GAO/AIMD-97-110.

Direct Loans Resulted in Net Financing Costs to the Federal Government

In a September 1997 report,[4] we estimated that RUS' net financing cost to the federal government for its electricity loan program totaled about $3.8 billion (in constant 1996 dollars) cumulatively in fiscal years 1992 through 1996. This net financing cost exists because the annual interest income received from RUS borrowers is substantially less than the federal government's annual interest expense on funds provided to borrowers. In addition, interest income is affected by favorable rates and terms given to some borrowers and also by financially troubled RUS borrowers that have missed scheduled loan payments. For example, one G&T borrower has not been required to make interest payments on its $4.2 billion debt since filing for bankruptcy in December 1994. Meanwhile, the federal government continues to incur interest expense on financing related to this borrower.

In April 1997, we reported that during fiscal years 1992 through 1996, RUS made or provided guarantees on 880 electricity loans, which totaled about $4.35 billion. Direct loans accounted for 835 of the total number of loans and for about $3.3 billion of the total amount of loans. The other 45 electricity loans had RUS guarantees. About 59 percent of the electricity loans were direct loans made at a 5 percent interest rate; these loans accounted for about 42 percent of the total dollar amount of all electricity loans.[5]

Until the Congress amended the Rural Electrification Act in 1973, almost all financing was through direct loans from REA to electric borrowers at a fixed rate of 2 percent with maturities up to 35 years. The 1973 amendment increased the interest rate on the direct loans from 2 percent to 5 percent. The Congress amended the act again in 1993 to provide direct loans with an interest rate that is (1) tied to an index of municipal borrowing rates or (2) fixed at 5 percent. Most loans are now made at the municipal rate with or without a 7-percent cap. Certain borrowers with customers that have low consumer and household incomes and high residential retail rates qualify for a loan at the 5 percent hardship interest rate.

[4] Federal Electricity Activities: Appendixes to the Federal Government's Net Cost and Potential for Future Losses, Volume 2 (GAO/AIMD-97-110A, Sept. 19, 1997).

[5] Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio (GAO/RCED-97-82, Apr. 11, 1997).

RUS' Outstanding Loans Are Owed by Borrowers With Favorable Financial Characteristics

In our April 1997 report,[6] we found that a majority of electricity borrowers had generally favorable financial characteristics at the end of calendar year 1995. For example, we found that 804 distribution borrowers had average assets of $37.4 million, liabilities of $21.6 million, and a net worth of $15.8 million. Only two of these borrowers had a negative net worth, and these two borrowers owed about $32 million on their outstanding loans as of September 30, 1996. Of 51 power supply borrowers with outstanding electricity loans at the end of 1995, 8 had a negative net worth. Seven of these eight borrowers owed about $6.1 billion on their outstanding electricity loans as of September 30, 1996.[7]

Most of the borrowers also had a net income at the end of 1995. All but 34, or 4.2 percent, of the electricity distribution borrowers had a net income in 1995. The 34 borrowers that had a loss owed $359 million on their outstanding electricity loans as of September 30, 1996. Furthermore, 10 of these 34 borrowers had losses in at least 1 year between 1992 and 1994. Only four of the power supplier borrowers did not have a net income in 1995. These four borrowers owed $866 million for their outstanding electricity loans as of September 30, 1996. In addition, two of these four borrowers had losses in at least 1 year between 1992 and 1994.

About One-Third of Outstanding Loan Debt Was Owed by Borrowers With Financial Problems

As of September 30, 1996, RUS' borrowers owed about $32.3 billion in outstanding debt on RUS' electricity loans. As we reported in September 1997, about $10.5 billion of the $32.3 billion was owed by 13 financially stressed borrowers. Borrowers considered financially stressed have either defaulted on their loans, had their loans restructured but are still experiencing financial difficulty, filed for bankruptcy, or have formally requested financial assistance from RUS. Of these 13 financially stressed borrowers, 4 borrowers are in bankruptcy and have a total of about $7 billion in outstanding debt. The remaining nine borrowers have investments in uneconomical generating plants and/or have requested financial assistance in the form of debt forgiveness from RUS. According to RUS officials, these plant investments became uneconomical because of cost overruns, continuing changes in regulations, and soaring interest rates. These investments resulted in high levels of debt and debt-servicing requirements, making power produced from these plants expensive. Most of the electricity loans to RUS' problem borrowers were made many years ago—some dating back to the 1970s.

[6]GAO/RCED-97-82.

[7]The electricity loans of the eighth borrower were settled on September 13, 1996, when the borrower made a partial payment and RUS wrote off the remaining debt.

Substantial Loan Write-Offs Occurred in Recent Years

During fiscal years 1996 and 1997, RUS wrote off about $1.6 billion in loans to rural cooperatives. In our September 1997 report, we reported that in fiscal year 1996, one G&T borrower made a lump sum payment of $237 million to RUS in exchange for RUS writing off and forgiving the remaining $982 million of its loan balance. This borrower's financial problems stemmed from its participation in a nuclear plant construction project that experienced lengthy delays as well as severe cost escalation. When construction of the plant began in 1976, its total cost was projected to be $430 million. However, according to the Congressional Research Service, the accrued expenditures by 1988 were $3.9 billion as measured in nominal terms (1987 dollars). These cost increases are primarily the result of changes in the Nuclear Regulatory Commission's health and safety regulations after the Three Mile Island accident. The remaining increases are generally the result of inflation over time and capitalization of interest during the delays.

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

Additional Losses From Electricity Loans May Occur in the Future

In addition to the financially stressed loans, RUS has loans outstanding to G&T borrowers that are currently considered viable by RUS but may become stressed in the future because of high costs and competitive or regulatory pressures. We believe that some losses to the federal government from currently viable loans are probable in the future.[8] We believe the future

[8]We based our discussion of the risk of nonrecovery on Statement of Federal Financial Accounting Standards No. 5, Accounting for Liabilities of the Federal Government, which indicates that if the chance that a contingent loss will occur is more likely than not, then the loss is considered "probable"; if the chance is more than remote but less than probable, then the loss is considered "reasonably possible"; and if the chance is slight, then the loss is considered "remote."

viability of these G&T loans will be determined on the basis of the borrower's ability to be competitive in a deregulated market. For example, 27 of 33 loans to G&T borrowers had high average production revenues in comparison to regional investor-owned utilities, and 17 of the 33 had higher average production revenues than publicly owned utilities. The relatively high average production costs indicate that the majority of G&T borrowers may have difficulty competing in a deregulated market. According to RUS, several borrowers had already requested forgiveness or a restructuring of their debt because they did not expect to be competitive because of high costs. However, RUS officials stated that they will not write off debt solely to make borrowers more competitive.

GAO's Prior Work on the Bonneville Power Administration

The Bonneville Power Administration (Bonneville), the largest of the power marketing administrations (PMA) in terms of generating capacity and sales, has been a low-cost supplier of electricity. In September 1997, however, we noted that its power has lost some of its price advantage, as a result of such factors as low prices for natural gas (the fuel used by Bonneville's competitors to generate low-cost power), surplus generating capacity on the West Coast, the opening of the competitive wholesale electricity market, and the resulting decline in electricity prices. It has also had higher costs because of requirements for fish recovery, resource acquisitions, and other factors. Bonneville's ability to reduce costs is hampered by the fact that a large part of its costs are fixed. The ultimate risk, should Bonneville be unable to cover its costs, will be the Treasury's.[1]

Bonneville Markets Power in the Pacific Northwest

Bonneville was created in 1937 by the Bonneville Project Act, originally as an interim agency to market electric power produced by the Bonneville Dam, then under construction on the Columbia River. In 1940, Bonneville's marketing responsibilities were broadened to include the power from Grand Coulee Dam in central Washington. Today, Bonneville markets electric power from the Federal Columbia River Power System, which consists of 29 federally owned hydroelectric projects, most of which are in the Columbia River Basin, and one nonfederal nuclear plant of the Washington Public Power Supply System. The Federal Columbia River Power System provides roughly half the power used in the Pacific Northwest. Bonneville, the Corps of Engineers, and the Bureau of Reclamation coordinate the system's operation with many public and privately owned utilities that own dams on the river system.

Like other PMAS, Bonneville sells primarily wholesale power from the dams and other generating plants to public and private utilities and direct service industries. By law, it gives preference to public utilities and sells excess power only outside of its primary customer service area—300,000 square miles in the Pacific Northwest, made up of Idaho, Oregon, Washington, western Montana, and small portions of California, Nevada, Utah, and Wyoming.[2]

Bonneville builds, owns, and operates over 15,000 miles of transmission lines that make up 75 percent of the Northwest's high-voltage transmission

[1]GAO/AIMD-97-110.

[2]In December 1997, Bonneville announced that it would begin selling power to its first preference customer in eastern Montana.

capacity. Over the years, the Congress has expanded Bonneville's mission to include conservation and renewable resource development, rate relief for specified residential and small farm power users, and specific mandates for fish and wildlife protection and funding.

Bonneville's Power Program Is to Be Self-Supporting

Unlike the other PMAS, Bonneville no longer receives an annual appropriation from the Congress. The Federal Columbia River Transmission System Act of 1974 placed Bonneville on a self-financing basis—its operating expenses are to be paid for by revenues from the sale of power and transmission service. Funds received from customers are paid to Bonneville, which then deposits the receipts into a special Bonneville fund at the Treasury. Expenditures for Bonneville are paid from that special fund. For capital expenditures, Bonneville has the authority to borrow from the Treasury. Its Treasury bond borrowing authority is capped at $3.75 billion ($2.5 billion for transmission and other capital investments and $1.25 billion for conservation and renewable energy investments). Bonneville is required to set its rates for power and transmission sales at levels that generate revenues sufficient to cover annual expenses and pay back previously appropriated funds. Bonneville is required to make an annual payment to Treasury that includes debt-servicing costs on appropriated debt and Treasury bonds. Similar to the other PMAS, Bonneville is also required to recover and repay to the Treasury the operating agencies' power-related capital and operating expenses.

Bonneville's Debt Exceeds $17 Billion

Unlike the other PMAS, Bonneville has a legislative mandate that requires it, within certain limits, to provide sufficient firm power to meet the needs of the customers in its primary service area. Because of this mandate, and in response to its estimate of growing energy demand in the Pacific Northwest, Bonneville entered into nonfederal financing agreements to acquire all or part of the capability of four nuclear power plants constructed, owned, and to be operated by other entities. As part of these agreements, Bonneville was required to pay the projects' annual costs, including debt service, in amounts ranging from 30 to 100 percent of total costs incurred. Later, a variety of events, including construction cost overruns and overly optimistic estimates of electricity demand, made it clear that some of these plants would not be economical to complete or operate. Accordingly, construction was halted on two of these nuclear plants and they were not completed. In addition, one previously operating plant has been shut down permanently. As a result, Bonneville is responsible for about $4.2 billion in nonfederal debt associated with three nonoperating nuclear plants and an additional $2.5 billion in nonfederal debt associated with the one operating nuclear plant.[3] Bonneville's total debt exceeded $17 billion, as of September 30, 1996.

Risk of Loss From Bonneville Is Remote Through Fiscal Year 2001 but Increases Thereafter

Bonneville's high fixed costs limited its ability to respond to competition by decreasing rates and contributed to a loss of customers in recent years. Although we concluded in a September 1997 report that the risk of any significant loss to the federal government from Bonneville is remote through fiscal year 2001,[4] thereafter, the expiration of customer contracts, risks from market uncertainties, Bonneville's high fixed costs, and upward pressure on operating expenses increase the risk of loss to the federal government.[5] Despite a number of factors that mitigate this risk, we reported that it is reasonably possible that the federal government will incur losses from Bonneville after fiscal year 2001. In addition, one small project that serves Bonneville represents a probable loss to the federal government.

Key Factors Stabilize Bonneville Through Fiscal Year 2001

Three key factors have stabilized the government's risk of loss attributable to Bonneville through fiscal year 2001 and, in our view, make risk remote for this period. First, in 1995 and 1996, Bonneville signed its customers to contracts to purchase a substantial amount of power through fiscal year 2001. Bonneville projects that firm power sales to these customers will secure about $1.14 billion annually through fiscal year 2001, or 63 percent of each year's total projected power revenues. Second, Bonneville's management entered into a memorandum of agreement with various federal agencies that has limited its fish mitigation costs through fiscal year 2001. This agreement also created a contingency fund of $325 million

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

[4]GAO/AIMD-97-110.

[5]We based our discussion of the risk of nonrecovery on Statement of Federal Financial Accounting Standards No. 5, Accounting for Liabilities of the Federal Government, which indicates that if the chance that a contingent loss will occur is more likely than not, then the loss is considered "probable"; if the chance is more than remote but less than probable, then the loss is considered "reasonably possible"; and if the chance is slight, then the loss is considered "remote."

for Bonneville's past nonpower fish mitigation expenditures.[6] Finally, Bonneville had strong water years in 1996 and in 1997 and estimates that it will have a financial reserve of about $400 million at the end of fiscal year 1997.[7] In addition, the $325 million fish cost contingency fund is available under specified circumstances.

Risk Increases After Fiscal Year 2001

After fiscal year 2001, Bonneville faces the expiration of customer contracts, significant market uncertainties, high fixed costs, and significant upward pressure on operating expenses. Nearly all of Bonneville's power contracts with customers expire at the end of fiscal year 2001. If these customers can find power cheaper than Bonneville can offer, they may opt to leave Bonneville. One of the key market uncertainties that will determine whether cheaper power will be available is the future production cost of gas-fired generation plants. This generation source has become increasingly competitive because of low natural gas prices and improving gas turbine technology. Natural gas prices in the Pacific Northwest are low as the result of several factors, including a large supply coming from Canada. Also, recent technology advances have improved the efficiency of gas turbines by more than 50 percent. According to Bonneville, natural gas-generated power has driven down the price of wholesale electricity and resulted in customers leaving or obtaining some of their power at rates well below Bonneville's current rate.

According to Bonneville, a surplus of power on the West Coast is also driving down the price of wholesale power. Because utilities still are able to pass on fixed costs to captive retail customers, surplus wholesale power is being sold on a marginal cost basis. According to Bonneville, other utilities and power marketers[8] are offering wholesale power as low as 1.5

[6]The Northwest Power Act requires Bonneville to protect, mitigate, and enhance fish and wildlife resources to the extent these resources are affected by federal hydroelectric projects. The act also directs Bonneville to allocate fish and wildlife costs to the projects' various purposes, for example, flood control, irrigation, and power. The reserve represents the portion of Bonneville's expenditures that are related to nonpower uses of the projects. To the extent Bonneville uses the $325 million reserve, the federal government will incur these costs because the memorandum of agreement allows it to apply the $325 million, under specified circumstances, as a credit against its Treasury payment.

[7]Bonneville's financial reserves of about $400 million include cash and deferred Treasury borrowing authority. Deferred borrowing authority is created when Bonneville uses operating revenues to finance capital expenditures in lieu of borrowing. This temporary use of cash on hand instead of borrowed funds creates the ability in future years to borrow money, when fiscally prudent, to liquidate revenue-funded activities. The deferred Treasury borrowing authority is similar to an unused line of credit. While this may be useful in the short term to provide liquidity, its use results in additional debt; thus, deferred borrowing authority is not a long-term solution to financial difficulty.

[8]Power marketers are subsidiaries of IOUs or independent companies that buy and sell power, typically on a wholesale basis.

cents per kilowatthour (kWh), which is lower than Bonneville's 2.14 cents per kWh for sales of comparable products. However, it is uncertain whether surplus power and low-cost natural gas generation will continue to drive down wholesale power prices after fiscal year 2001.

It is also uncertain what impact retail open access will have on Bonneville's competitive position. Retail open access—which would provide retail consumers the freedom to choose among suppliers—could result in Bonneville's wholesale customers being uncertain about the size of their own future power needs. These power needs will be directly affected by retail customers' choices about their suppliers. Bonneville's customers may be hesitant to sign long-term contracts to purchase power from Bonneville to the extent that they face uncertainty about future power needs. However, even without long-term contracts, Bonneville is likely to remain a major supplier.

Bonneville's substantial fixed costs will continue to inhibit its flexibility to lower its rates and meet competitive pressures. For example, 32 percent of Bonneville's revenue went to pay financing costs in fiscal year 1996—substantially more than a nationwide average of 14 percent for IOUs and 18 percent for publicly owned generating utilities. After fiscal year 2001, Bonneville will continue to face high fixed costs relating to its $17 billion debt.

Bonneville will also face significant upward pressure on its operating expenses after fiscal year 2001. The most significant of these operating expenses is fish mitigation. It is uncertain whether an agreement similar to the current agreement will be possible after the present one expires. Without this agreement, Bonneville is at risk of escalating costs after fiscal year 2001 if additional funds for fish measures beyond those planned at this time are needed.[9] Bonneville also faces new or additional costs after 2001. First, it plans to implement a phased-in approach to recovering the full cost of pension and postretirement health benefits in fiscal year 1998 but will defer full recovery until fiscal year 2002, when $55 million will be due. To completely recover obligations for fiscal years 1998 through 2001, an additional $35 million will be due in fiscal year 2003. Other new or additional costs that will be incurred after fiscal year 2001 include $806 million in irrigation debt payments and $396 million in payments to the Confederated Tribes of the Colville Reservation for the tribes' share of

[9]If total federal mitigation costs increase and Bonneville reduces or caps its fish mitigation expenses after 2001, the federal government may have to bear additional costs.

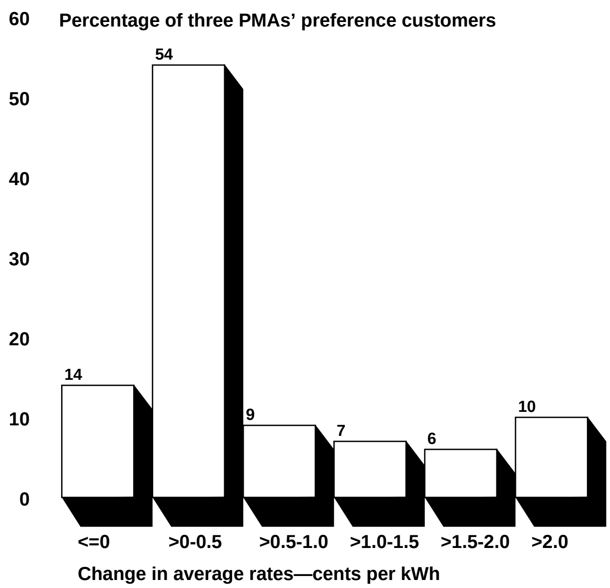
the Grand Coulee Dam revenues. These costs would be paid out over several decades.

Mitigating Factors Reduce Probability of Loss

Several factors mitigate the federal government's risk of future losses relative to Bonneville. These factors include certain inherent cost advantages, management actions to reduce operating costs, and an extensive transmission system. We believe that these factors reduce the risk of loss to the federal government after 2001 but that the risk is still reasonably possible. Moreover, Bonneville is scheduled to have nearly all of its nonfederal debt paid off by 2019, with a substantial decrease in debt service beginning in 2013. If Bonneville is able to make these payments as scheduled, all else being equal, its fixed financing costs would be more in line with those of its competitors. This would reduce the risk to the federal government. As shown in figure III.1, Bonneville's 1995 average revenue per kWh was more than 15 percent lower than the average revenues of IOUs and publicly owned generating utilities in the primary North American Electric Reliability Council[10] region (Western Systems Coordinating Council) in which Bonneville operates.

[10]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. The Council consists of 10 regional reliability councils and encompasses essentially all the power systems of the contiguous United States, as well as parts of Canada and Mexico.

Figure III.1: Average Revenue per kWh for Wholesale Power Sold in 1995 for Bonneville, IOUs, and Publicly Owned Generating Utilities



Legend: Bonneville - Bonneville Power Administration; IOU - Investor-owned utility

Note: The latest data available for IOUs and publicly owned generators were for 1995. We included Bonneville's 1996 average revenue per kWh to show that it decreased almost 20 percent from 1995 to 1996.

Source: GAO's analysis of Bonneville's annual reports, preliminary (unaudited) 1995 IOU data from the Energy Information Administration, and publicly owned generators' data from the American Public Power Association.

As previously mentioned, Bonneville is facing significant competition. However, its management believes that its average production costs are less than those of others in the Pacific Northwest, as shown in figure III.1. If the supply of surplus power dwindles and gas generation costs rise, which Bonneville believes will happen, Bonneville's low average production costs should improve its long-term competitive position. This long-term position will be further improved after 2012 if Bonneville repays its nonfederal debt as scheduled.

Bonneville has comparatively low average production costs because of certain inherent cost advantages it has over nonfederal utilities. For example, in 1996 Bonneville did not recover nearly $400 million of the costs associated with producing and marketing federal power. In addition, the hydroelectric plants that generate the power marketed by all the PMAS have cost advantages over coal and nuclear generating plants, which generate over 81 percent of the electricity in the United States. Bonneville's hydroelectric plants, which were built decades ago, also had relatively low construction costs compared with newer, nonfederal utilities' construction. Other advantages are that Bonneville, like the other PMAS, generally does not pay taxes, and the interest income that bondholders receive from Bonneville's nonfederal debt is exempt from the federal personal income tax and some state income taxes.

Bonneville's management has taken significant steps in the last several years to respond to the intense wholesale electricity competition in the Pacific Northwest. According to Bonneville, its staff decreased from about 3,755 in March 1994 to 3,160 by the end of fiscal year 1996. An additional reduction to 2,755 is planned by fiscal year 1999. In addition, over the last several years, Bonneville has refinanced much of its Treasury bonds and nonfederal debt to keep its interest expense as low as possible. According to Bonneville, these staffing and other cost savings will reduce planned expenses by an average of $600 million per year during fiscal years 1997 through 2001 and have allowed a 13-percent rate decrease for those years.

Bonneville also has an extensive transmission system that constitutes about 75 percent of the bulk power transmission capacity in the Pacific Northwest. According to Bonneville, if it is unable to sell its power at a level that recovers all costs, it may be able to use revenues from the sale of transmission services to help recover stranded costs.[11] This could involve allocating stranded generation costs, in whole or in part, to transmission charges.

Risk of Loss From Teton Dam Project Is Probable

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

[11]As defined by FERC, a stranded cost is any legitimate, prudent, and verifiable cost incurred by a public or transmitting utility that is no longer economically viable in a competitive wholesale environment.

Since the failure of the dam in 1976, the project's costs have been carried on the books of the Bureau as construction work-in-progress. While assets of this type normally accrue interest charges, the Teton project has accrued no interest since 1976. Since that time, interest charges of about $5 million, at the project's interest rate of 3.25 percent, would normally have been paid to the Treasury, as we reported in September 1997.[12]

The project's power-related construction costs are part of Bonneville's appropriated debt balance. However, provisions to recover this amount have not been made. According to Bonneville, since the project was not formally completed and placed in service, its costs cannot be put into Bonneville's rates. According to the Bureau, it has no plans for further construction at the site and the project should be written off; however, according to the Bureau, a write-off would require deauthorization of the project by the Congress. Whether or not the project is deauthorized, we believe these costs are unlikely to ever be recovered.

[12]GAO/AIMD-97-110A.

Objectives, Scope, and Methodology

From the early 1900s through September 30, 1996, federal agencies that generate and/or market electricity and that make or guarantee loans to finance improvements to electricity systems incurred a debt of about $84 billion.[1] Like the other federal agencies, the Southeastern, Southwestern, and Western Area power administrations—responsible for about $7 billion of this debt—face an uncertain future as electricity markets restructure. In response, the Chairmen of the House Committee on Resources and the Subcommittee on Water and Power asked us to focus on these three power marketing administrations (PMA) and (1) to examine whether the government operates them and the related electric power assets in a businesslike manner that recovers the federal government's capital investment in those assets and the costs of operating and maintaining them and (2) identify options that the Congress and other policymakers can pursue to address concerns about the role of the three PMAs in emerging, restructured markets or to manage them in a more businesslike fashion. Our options also have implications for the Army's Corps of Engineers (Corps) and the Department of the Interior's Bureau of Reclamation (Bureau), which generate most of the power these PMAs market. As requested, the report also provides information on the Tennessee Valley Authority (TVA), Rural Utilities Service, and Bonneville Power Administration (Bonneville), which is contained in appendixes I, II, and III, respectively.

We also included in this report information from our more generalized reports that address topics concerning the ways that federal agencies can be operated in a more businesslike fashion. See Related GAO Products at the end of this report for a list of the products we used.

Examining Whether the Government Operates Its Power Assets to Recover Costs and Promote Repayment of the Federal Investment

To examine whether the federal government operates its electric power and related assets in a manner that recovers the associated costs and promotes the repayment of the federal investment in those assets, we first researched the history of the nation's electric power industry, focusing on the evolution of markets and regulatory structures. Our work included reviewing the effects of major statutes and their amendments, such as the Federal Power Act of 1920, the Public Utility Holding Company Act of 1935, the Public Utility Regulatory Policies Act of 1978, and the Energy Policy Act of 1992. In addition, we examined the roles of investor-owned utilities; cooperatives; publicly owned, nonfederal utilities (that is, those owned by state, municipal, or other nonfederal public entities); federal generators and marketers of power utilities (including the PMAs, the

[1] GAO/AIMD-97-110.

operating agencies, and TVA), and RUS. We monitored current changes in the industry, especially those pertaining to restructuring and retail competition, by contacting associations of electric power providers in Washington, D.C. (the American Public Power Association, the Edison Electric Institute, the National Hydropower Association, and the National Rural Electric Cooperatives Association), DOE, the PMAS, and the Federal Energy Regulatory Commission (FERC) and by reviewing state public utility commission homepages on the Internet and industry publications.

In addition, we reviewed our recent products on the business practices of the PMAS and the operating agencies, including (1) whether the PMAS' rates recover all of the costs associated with generating, transmitting, and marketing electricity and (2) the related costs that are assigned to power for repayment, such as assistance to irrigation, and the rate and repayment methodologies of the PMAS. To the extent deemed appropriate, we followed up on issues from our prior work with field work at various locations of Southeastern, Southwestern, Western, the Bureau, the Corps, and various power customer groups (namely, the Southeastern Federal Power Customers, Atlanta, Georgia, and the Midwest Electric Consumers Association, Denver, Colorado). For example, at the Billings office of the Bureau, we updated previous information about the Bureau's efforts to recover over $450 million in federal investment in hydropower capacity and reservoir storage for planned irrigation projects.

Identifying Options for the Three PMAs and Their Operating Agencies

We identified options that the Congress and other policymakers can pursue to address concerns about the role of these three PMAS in restructuring markets or to manage them in a more businesslike fashion. To identify these options, we consulted officials from the American Public Power Association, the Edison Electric Institute, the National Hydropower Association, the National Rural Electric Cooperatives Association, and the Office of Management and Budget, in Washington, D.C. In addition, we contacted the Bureau, the Corps' Hydropower Coordinator, and DOE's Power Marketing Liaison Office (on behalf of Southeastern, Southwestern, and Western), and the Department of the Interior. We also contacted the Bureau's offices in Billings, Montana; Denver, Colorado; Sacramento, California; and Salt Lake City, Utah. We discussed options with representatives of Southeastern in Elberton, Georgia; of Southwestern in Tulsa, Oklahoma; and of Western in Billings, Montana; Golden, Colorado; and Salt Lake City, Utah. We also discussed options with or obtained information from the PMAS' preference customers or customer groups, such as the Midwest Electric Consumers Association and Western States

Power Corporation, Denver, Colorado; the Southeastern Federal Power Customers, Inc., Atlanta, Georgia; and the Southwestern Power Resources Association, Tulsa, Oklahoma; and, in some cases, their legal counsels.

A primary task in examining the option to divest the PMAS was to estimate the effects of a divestiture on the rates paid by the PMAS' customers. In this connection, we estimated how much the PMAS' existing customers' rates might change if the PMAS were sold. To calculate these changes, we compared (1) the average blended rate that each PMA customer paid for wholesale power from all sources in 1995 with (2) the wholesale rate that each PMA customer might pay after divestiture. The difference in these two rates equals the change in rates attributable to a divestiture.

Estimating the potential rate changes required several steps and assumptions. First, we estimated the average rate that each PMA customer paid for PMA and non-PMA power in 1995. To calculate how much customers paid for the PMAS' power, we obtained data from Southeastern's, Southwestern's, and Western's fiscal year 1995 annual reports. Then, to learn how much each PMA customer paid for the wholesale power it purchased from other sources, we used the sales for resale databases compiled by DOE's Energy Information Administration (EIA).[2] We found that for about one-third of the PMAS' total customers, EIA's data lacked the volumes of wholesale power the customers purchased from non-PMA sources, the amount the customer paid for the power, or both.[3] In these cases, we assumed the customer paid a rate equal to the average market rate paid by customers of the same type (for example, municipal utilities and cooperatives) for wholesale power in the customer's state. We then blended each customer's PMA and non-PMA purchases to estimate how much the customer paid for wholesale power from all sources in 1995.

Second, to estimate how much each PMA customer would pay for power after a divestiture, we assumed each PMA customer would pay a rate that equals the average rate it paid for wholesale power from sources other than the PMAS in 1995. We used this assumption because it is likely that in the period immediately after a divestiture, the new owners of the PMAS' assets would charge the prevailing market rates for wholesale power in the area. We took this approach because we were unable to obtain forecasts of future wholesale rates. Although EIA recently used its National

[2]Specifically, we used EIA's PURCH.Y95 and SALES.Y95 databases.

[3]EIA officials stated that the data were missing for several reasons, among them that the PMA customers involved were so small they did not have to file the reports (FERC's Form 1, DOE's Form 412) that EIA uses to compile the sales for resale data.

Energy Modelling System to forecast future electricity rates,[4] according to the agency, its projections are only for retail rates.[5] Other projections of future wholesale rates were proprietary.

Finally, after calculating how much each PMA customer paid for PMA power in 1995 and how much it would pay for PMA power after a divestiture, we calculated the difference (both in percentage and cents per kWh) between the two rates. These differences represent our estimates of each customer's potential increase in average blended rates following a divestiture of the PMAS.

It is important to note that because we assume, after divestiture, that each customer will pay a rate for power that equals what the customer paid for non-PMA power in 1995, our methodology is conservative. If prices for wholesale power decline in the future, as many industry analysts believe they will, each customer's change in rates from divestiture of the PMAS will be smaller than our estimates.

To estimate how each preference customer's rate change would affect the rates paid by its residential end-users, we assumed that (1) each preference customer would pass all the rate increase from divestiture onto its end-users and (2) that residential end-users consume 10,037 kWh of electricity per year. The monthly increase in a residential end-user's electricity bill equals the preference customer's rate increase after divestiture (in cents per kWh) times residential end-users' average annual electricity consumption (10,037 kWh), divided by 12.

We conducted our review from April 1997 through February 1998 in accordance with generally accepted government auditing standards.

We provided a draft of this report to the Department of Defense (including the Corps); Bonneville; DOE's Power Marketing Liaison Office that represented the views of Southeastern, Southwestern, and Western; the Department of the Interior (including the Bureau); and FERC. Their comments and our responses are included in appendixes VI, VII, VIII, IX, and X, respectively.

[4]See Electricity Prices in a Competitive Environment (DOE/EIA-0614, Aug. 1997).

[5]We attempted to derive forecasts of wholesale prices from EIA's retail price forecasts by subtracting distribution costs from EIA's projections. However, we found that our result was much higher than the national average rate for wholesale power EIA reports in Financial Statistics of Major U.S. Investor-Owned Utilities. After consulting with EIA, we chose not to use its retail price forecasts because they are based on EIA's judgmental assignment of electricity generators' costs to services, such as generation, transmission, and distribution, rather than actual sales data.

Projects and Rate-Setting Systems of the Three PMAs Where the Federal Investment Is at Risk

As shown in chapter 2, up to $1.4 billion in federal investment is at various degrees of risk for nonrecovery at six of Southeastern's, Southwestern's, and Western's projects and rate-setting systems.[1]

Richard B. Russell Project

The Russell project, located on the Savannah River, which is the border between Georgia and South Carolina, has four conventional hydropower generating units (300 MW), which are operating, and four pumping units (300 MW), which have not operated as intended.[2] Because of litigation over large fish kills, the pumping units, which were completed in 1992, have not been allowed to operate commercially. As a result, the construction cost associated with them has been excluded from power rates and is not being recovered. Moreover, the interest associated with these capital costs has not been paid to the Treasury each year. Instead, this interest—estimated at about $29.9 million for fiscal year 1996—has been capitalized and added to the construction-work-in-progress balance each year. As of September 30, 1996, we estimate that the balance in the construction-work-in-progress account was about $518 million. According to Southeastern's power customers, if the pumping units become operational, then the construction costs would be recovered through rates that, consequently, would increase by about 25 percent for customers of Southeastern's Georgia-Alabama-South Carolina rate-setting system. According to Southeastern's customers, even with this increase, the system's rates would remain competitive. In our view, if the construction-work-in-progress costs are put into the rates in the near future, then the risk of nonrecovery of the $518 million remains. However, the longer the delay in operating the four pumping units, the greater the risk of nonrecovery because the amount to be recovered will also increase. At some point, the price of the power for the Georgia-Alabama-South Carolina system may become noncompetitive, and in such a situation, we believe the risk of some loss to the federal government is reasonably possible. If the pumping units are never allowed to function, then it is probable that the federal government will lose its entire $518 million investment. In commenting on our draft report, DOE's Power Marketing Liaison Office noted that some unspecified portion of

[1]We based our discussion of the risk of nonrecovery on Statement of Federal Financial Accounting Standard No. 5, Accounting for Liabilities of the Federal Government, which states that if the chance that a contingent loss will occur is more likely than not, the loss is to be described as "probable"; if the chance is more remote but less than probable, it is "reasonably possible"; if the chance is slight, it is "remote."

[2]During periods when the demand for power is low, pumping units return water that has passed through the generating units to the reservoir so that water can be reused to produce power during periods when demand is higher.

this investment will be recovered even if the units are never commercially operated.

Harry S. Truman Dam and Reservoir

The Truman project, located on the Osage River in Missouri, has six hydropower generating units (160 MW of nameplate capacity) placed in service from 1980 to 1982 that are intended to act both conventionally and as pumping units. Because of design problems and fish kills caused by the pumping capability, the generating units have operated only as conventional units, not as pumping units. Only 53 MW of generating capacity were declared to be operable. Consequently, it was determined that the costs associated with the capacity that has not been allowed to operate commercially should not be included in Southwestern's power rates. Southwestern petitioned FERC to defer recovery of these costs. In 1989, FERC concurred with Southwestern. Thus $31 million is not being recovered through power rates until the pumping units work as designed. According to Corps officials, three of the six units are now in service, operating as conventional, not pumping, units. Two more units were to be rehabilitated and placed back on line by February 1998, and the last unit is to be back on line by February 1999. These last three units, however, will also operate only in a conventional mode pending lifting of an injunction by the State of Missouri. Corps officials stated that although the modifications should increase the availability of the generating units, the fish kill issue has not been resolved and associated capacity has not been restored as a result. Unless the pumping capacity becomes operational, which we believe is unlikely given the amount of time it has been inoperable, it is probable the government will lose the $31 million invested in it. If the units do come on line as designed, then the risk of future losses is remote. In commenting on our draft report, DOE's Power Marketing Liaison Office noted that Southwestern can add to its power repayment study the power-related costs of the pumpback units even if the units are never operable.

Central Valley Project

California's Central Valley Project had an outstanding appropriated debt of $267 million as of September 30, 1996, and its hydropower program incurred a loss of $24 million in fiscal year 1996. The project has an installed generating capacity of about 2,000 MW at 12 hydropower plants. Faced with competition from low-cost producers, Western cut the project's power rates by 26 percent in fiscal year 1996. As stated in chapter 1 of this report, Western also announced a decrease of over 20 percent, effective October 1, 1997, in the composite rates of power it markets from hydropower plants in the Central Valley Project. These rate cuts were facilitated, in part, by renegotiating contracts that obligate Western to purchase power for its customers if the project cannot supply enough. We believe that the extent to which any of Western's rate cuts will be sustainable at competitive levels is unclear. Moreover, the success of Western in reestablishing and sustaining the competitiveness of the project's power is uncertain because of environmental legislation. The Central Valley Project Improvement Act of 1992 adds fish and wildlife mitigation, protection, and restoration as authorized purposes for the project, thus restricting the use of water for purposes such as hydropower generation, irrigation, and municipal and industrial water. These restrictions may reduce the amount of power generated and make it uncertain whether revenues from the sale of whatever amount of power that can be produced will repay the federal investment in hydropower and other costs allocated for repayment through power revenues. For example, according to the Bureau, an analysis of environmental impacts indicates that the management of 800,000 acre-feet of water in the project for environmental purposes may result in a reduction of about 5 percent in hydropower production. Moreover, according to Western officials, when the reallocation of water required by the act occurs, substantial nonpower costs may be reallocated to power for repayment, thus placing further upward pressure on Western's power rates. This situation will reduce Western's ability to restore the competitiveness of the project's power rates, according to Western officials. The 1984 Trinity River Basin Fish and Wildlife Management Act also restricts the use of the project's water for generating electricity. These uncertainties, along with emerging competition, lead us to conclude that it is reasonably possible that some of the $267 million federal investment will not be repaid.

Pick-Sloan Missouri Basin Program

The Pick-Sloan Missouri Basin Program is a comprehensive plan to manage parts of 10 midwestern and western states that are drained by the Missouri River. The program's Eastern and Western divisions have a total generating capacity of about 3,100 MW at 13 power plants. In May 1996, we estimated that about $454 million of the federal investment in hydropower capacity initially designed for use by future irrigation projects and in costs associated with storing water for these projects would likely not be completed.[3] Although Western has scheduled these costs for repayment through power revenues, this will not occur until the future irrigation projects become operable. According to the Bureau, almost all of these

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

planned irrigation projects are infeasible and unlikely to be completed. Under applicable statutory repayment principles, recovery of these costs, which we estimate at $464 million as of September 30, 1996, cannot occur unless the associated irrigation projects come into service. Without legislative action, it is probable that Western will not be required to recover the principal or any interest on the $464 million.

Washoe Project

The Washoe Project with the associated Stampede Powerplant (10 MW), located in east-central California and west-central Nevada, is not generating sufficient revenue to cover its annual power-related operating expenses, interest, or the federal investment in it. Since 1988, deferred payments to the Treasury for its annual operating expenses and interest charges totaled about $4.1 million through the end of fiscal year 1996. The project also had $8.9 million in appropriated debt as of the end of fiscal year 1996. To compound matters, according to Western officials, the power plant would have to price its power at a noncompetitive level—about 5.7 cents per kWh, according to Western's estimates—to cover its operating expenses (less depreciation), interest, and debt repayments.[4] To recover the costs associated with the Washoe Project, Western officials told us that they were considering combining the Washoe Project's power with the power from the Central Valley Project and establishing a blended rate. However, because the Central Valley Project itself faces challenges in remaining competitive, we concluded that it is reasonably possible that the $13 million in deferred interest and federal capital investment will not be recovered. The risk of nonrecovery worsens to probable if the Washoe Project's power continues to be marketed on a stand-alone basis. In commenting on our draft report, DOE's Power Marketing Liaison Office noted that Western staff are proposing the blending of the costs of the power from the Washoe Project with those of Central Valley Project after the year 2004.

Mead-Phoenix Transmission Project

The Mead-Phoenix Transmission Project, involving a $94.7 million investment by Western, including capitalized interest, was intended to increase the power transmission capability between parts of Arizona, Nevada, and California. The project's expected demand has not materialized, and it is unclear whether Western will be able to market the project's capacity. From April 1996, when the project came into service, through January 1997, it had revenues of only $71,319, while incurring operation and maintenance and interest expenses of nearly $7.3 million,

[4]Power from the Washoe Project generated revenues of only 1.02 cents per kWh in fiscal year 1996.

resulting in a net loss of about $7.2 million. According to Western, if the project does not achieve the level of sales assumed in the transmission charges, the PMA will begin a new rate process to ensure recovery of the project's costs. Western is considering blending the project's rates into the overall transmission rates for the Pacific Northwest-Pacific Southwest Intertie. If the blending cannot be accomplished, we believe it is probable that the government will lose at least some of its $94.7 million investment in the Mead-Phoenix project. Even with the consolidation, we see no indication that demand for power from the project will increase or that the PMA will be able to successfully market the entire transmission capacity, and we therefore conclude that the risk of future losses to the government is reasonably possible.

Comments From the Department of Energy

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

January 28, 1998

Mr. Victor S. Rezendes
Director, Energy, Resources, and Science Issues
Resources, Community, and Economic Development Division
United States General Accounting Office
Washington, D.C. 20548

Dear Mr. Rezendes:

This letter serves as the written comments of the Southeastern, Southwestern, and Western Area Power Administrations on the General Accounting Office (GAO) draft report entitled Federal Power: Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry (GAO/RCED-98-43), dated March 1998. We appreciate the opportunity to comment on the draft report and to suggest modifications and technical corrections before it is released in final form.

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

See comment 1.

SUMMARY OF PMA COMMENTS

The three PMAs concur with the draft report's summary that there are instances where the PMAs do not recover the full costs of marketing Federal power, as defined by GAO. As the draft report notes, the PMAs' actions in these instances are allowable -- or even required -- under current law. Implementing changes will, in a number of cases, require Congress and the President to enact legislation. The PMAs are committed to recovering those costs legally required to be recovered through power rates.

The three PMAs disagree strongly with the magnitude of the "net costs" reported by GAO in their previous reports and repeated here in the draft "capping" report. The PMAs believe GAO has overstated the cost under recovery of low interest rate financing due to the use of an improper methodology for estimating the Treasury's cost of money. In addition, the PMAs believe there are certain costs GAO reports as unrecovered that the PMAs believe will be recovered in future years.

The draft report notes that there is risk that up to $1.4 billion of the federal investment in certain hydroelectric projects will never be recovered. The PMAs agree that, like private sector investments, the Federal investments identified in the draft report have some risk of nonrecovery, but believe the degree of risk is much smaller than GAO assumes.

The PMAs believe the draft report could benefit from additional discussion of actions the PMAs have taken to recover additional costs. The report acknowledges that the unfunded liability of Civil Service Retirement System costs is being recovered through power revenues, beginning in FY 1998. It also notes that Western has proposed a means to recover the capitalized deficit in the Washoe Project. However, acknowledgment of the use of current interest rates on Federal investments since 1983 and the recent actions Western has taken to include the cost of an abandoned transmission line in power rates and restructure rates for the Mead-Phoenix Project would be appropriate.

Finally, the report's discussion of the role of the PMAs in a restructured electric utility industry could be expanded to cover the steps the PMAs are taking to stay competitive. Examples that could be cited include: Western's Transformation process, budget reductions that led to cost savings and rate decreases, Southwestern's Organization 2000 Plus, and voluntary PMA compliance with FERC Order Numbers 888 and 889.

POLICY COMMENTS ON EXECUTIVE SUMMARY

See comment 2.

Incorporate Report Changes in the Summary. This letter recommends certain changes to the body of the draft report, as discussed below. We ask that changes adopted by GAO as a result of our comment letter be incorporated into the Executive Summary, as well.

POLICY COMMENTS ON CHAPTER 1: "INTRODUCTION"

See comment 3.

Discussion of Industry Structure and Public Power's Role is Incomplete. This chapter provides a brief overview of the electric utility industry in the United States. This discussion mentions public power entities (e.g. municipal electric departments, rural electric cooperatives) primarily in their capacity as "preference" customers who buy Federal power. The only justification cited for Federal power was its role in electrifying rural America. Competition in the industry is asserted to have begun in 1978 with the enactment of two Federal laws.

This discussion is too brief because it omits key roles played by public power and the Federal government in the evolution of the industry's structure. For example, public power has been an active competitor of investor-owned utilities since the early years of this century. By providing "yardstick" competition that allowed comparisons against the power rates of investor-owned utilities, public power entities played an important role in keeping electric rates down.

This competition was not limited to rural areas, although there is no question that rural electric cooperatives played a key role in bringing electricity to farm areas that investor-owned utilities did not find profitable to serve. Cities such as Los Angeles, Seattle, and Jacksonville are clearly not rural, yet they have public power service as a result of their citizens' choices many years ago.

Moreover, the mission of Federal power was not limited to electrifying rural areas. Another, broader mission was, and is, to promote economic development in those regions of the country the PMAs serve. Also, Federal power was provided preferentially to public utilities in order to promote competition and ensure that public (not private) interests benefitted from these public resources. It also provided a source of revenue to repay the U.S. Treasury for the government's investment in multipurpose water projects.

This discussion in Chapter 1 should give a more complete picture of the history of public power in the industry and the mission of Federal power.

See comment 4.

Description of PMA Compliance with FERC Order No. 888 Should be Added. Expanding upon their long-standing open access transmission policies, Southwestern and Western Area Power Administrations filed open access transmission service tariffs with the Federal Energy Regulatory Commission (FERC) on December 31, 1997. These tariffs will govern future access to available electric transmission, and are consistent with the tariffs of other wholesale transmission providers. The two PMAs will provide transmission service to others under the same terms and conditions they provide to themselves. The PMAs are seeking a declaratory order from FERC that these tariffs meet or exceed the requirements of FERC Order No. 888. The draft report's discussion of FERC Order No. 888 should include a description of the PMAs' recent actions.

See comment 5.

Discussion of PMA Responses to Increasing Competition Should be Expanded. Chapter 1 contains a discussion of how the electric utility industry is responding to increasingly competitive markets. A mention is made of Western's recent rate reduction for the Central Valley Project, but the PMAs have done considerably more to prepare for the competitive future that awaits this industry. Southwestern has reduced overhead costs by embarking on Organization 2000 Plus, which is a multi-year strategy to streamline the agency, reduce targeted administrative positions, cut the number of managers and supervisors, and eliminate one field office. Western began a process, called Transformation, to re-engineer its functional structure in 1995. Goals to be achieved include: a 24-percent reduction in Federal and contractor staff from FY 1994 levels, cost savings of $25 million annually, and significant reductions in formal organizational business units. In addition, Western has severely curtailed its construction program, from a FY 1994 level of $121 million to $38 million in FY 1998, in order to keep this activity from putting upward pressure on power rates. A discussion of these additional actions would add value to the report.

POLICY COMMENTS ON CHAPTER 2: "PMAS OPERATE AT A NET COST, HAVE GENERATING ASSETS THAT NEED REPAIR, AND PRESENT SOME RISK THAT FEDERAL INVESTMENT MAY NOT BE RECOVERED"

See comment 6.

PMAs can Agree with Certain of this Chapter's Findings. The PMAs agree that certain costs of the government's power program, as defined by GAO, have not been recovered and, hence, the program operated at a net cost to the government over the time period evaluated. We are glad to see that the draft report notes that the PMAs are generally following applicable laws and regulations in their cost recovery efforts. The PMAs appreciate the draft report's willingness to state that repayment of most of the Federal investment is "relatively secure" and that the three PMAs "are generally competitively sound." Moreover, just as private sector investments carry risks, we can agree with the draft report that there is some risk that the Federal investment in certain projects will never be recovered. However, the three PMAs take strong exception to the draft report's findings of the magnitude of the net costs, and the degree of risk of nonrecovery, as discussed below.

See comment 7.

Three PMAs' "Net Costs" Are Overstated. The $1.5 billion cited in the draft report as the amount of "net cost" to the Federal government from these three PMAs between 1992-1996 is primarily an interest rate financing cost. As our comments on previous reports have indicated, the three PMAs believe using the "portfolio method," which compares PMA average interest rates against the Treasury's average outstanding borrowing cost to determine the magnitude of the financing cost, is flawed. Because of this disagreement over methodology, the PMAs cannot concur with this draft report's estimate of the PMAs' net costs. A more extensive explanation of the PMAs' concerns is found on pages 150-151 of GAO report GAO/AIMD-97-110A. In addition, the Bonneville Power Administration took exception to this methodology for determining net financing costs: The three PMAs concur with Bonneville's comments found on pp.164-167 of GAO/AIMD-97-110A.

The three PMAs continue to disagree with the draft report's repetition of an earlier GAO report finding that flexible repayment terms allowing the repayment of highest interest debt first is a cause of the net financing cost. The PMAs believe the net financing cost is due solely to the choice of interest rates assigned to the Federal investments.

See comment 8.

Maintenance Situations of Operating Agencies Vary by Region. Although the PMAs will let the Bureau of Reclamation and Army Corps of Engineers provide the main comments on this point, the three PMAs report that the existence of maintenance problems vary by region, district, and/or division within the operating agencies. Within an operating agency, certain locations appear able to keep their facilities adequately maintained, while other locations are experiencing maintenance problems. Hence, problems in one area should not be extrapolated to all areas.

See comment 9.

Cause of Maintenance Problems Appears External to Operating Agencies, Not Internal. The draft report identifies the planning and budgeting problems used by the Federal agencies as the root cause of the operating agencies' maintenance problems. It is the PMAs' perception that the problem does not originate within the agencies, but rather with the Federal budgeting process as a whole. The long lead times between planning and execution in the Federal budgeting process contribute to maintenance problems. The same goes for the lack of funding flexibility. This point is addressed somewhat on page 48 of the draft, but previous references on pages 5, 9, and 42 seem to imply that it is the agencies themselves that have created the funding problem. The PMAs defer to the Bureau of Reclamation and the Army Corps of Engineers for definitive comments on this issue.

See comment 10.

Use of Average Revenue Per Kilowatt-hour is Overly Simplistic. As we have previously commented, the use of average revenue per kilowatt-hour may mislead the report's readers about the size and reasons for cost differences between the PMAs and other utilities. This measurement does not account for differences in the types of power (firm vs. nonfirm, on-peak vs. off-peak, etc.) sold by different utilities. In addition, for a hydropower-based utility, this measure will vary based on water conditions. Wide variations in the average revenue per kilowatt-hour of a utility from year to year suggest that this is not a good measure of the utility's competitiveness.

See comment 11.

Risk Table Should Reflect PMA Comments on Appendix V. The three PMAs have comments on the projects identified in Appendix V of the draft GAO report as being at risk for nonrecovery of the Federal investment. We recommend that our comments on Appendix V be incorporated into Table 2.1 on page 53 of the draft report, which summarizes Appendix V's findings.

POLICY COMMENTS ON CHAPTER 3: "OPTIONS FOR OPERATING FEDERAL HYDROPOWER ASSETS"

PMAs Agree with the Draft Report's References to Changes Requiring Congressional Action. The three PMAs noted that this chapter included references to the fact that many of the options discussed would require enactment of legislation. The PMAs agree with this assertion.

See comment 12.

PMAs Cannot Agree with Those Evaluations of the Three Options that Are Based on Previously Reported Findings with which the PMAs Do Not Concur. The draft report evaluates the three options under consideration, in part, by discussing whether the option will correct findings discussed in previous reports. To the extent that the PMAs disagree with previous reports' findings, we believe the evaluations are inaccurate or incomplete.

See comment 13.

Any Comparison of Options Should Use the Same Operating Conditions and Cost Recovery Requirements. We believe the authors of the draft report would agree that comparisons of the three options must be undertaken using the same assumptions about generating plant water release requirements and restrictions. (It is practically guaranteed that the Federal government will continue to impose such conditions.) Similarly, expectations about costs that must be recovered (e.g. multi-purpose costs allocated to power, irrigation assistance) should be consistent between options. Without consistency in the assumptions, side-by-side evaluations of various options will not be useful. In particular, the value of specific Federal assets under the divestiture option can vary widely based on the assumptions used.

See comment 14.

Regional Equity Under the Status Quo Needs More Discussion. The draft report cites as "debatable" the issue of PMAs' marketing power to customers in 34 states, but not in the remaining states. A thorough discussion of this issue would address: (1) the historical reasons why hydropower development occurred under Federal ownership in certain regions of the country, and under state or private ownership in other regions, (2) transmission limitations, and (3) the regional equity of all Federal government spending, not just hydropower. Virtually all Federal investment is regional in nature.

See comment 15.

Alternative Financing Does Not Reduce Oversight. The draft report cites Corps and DOE officials as cautioning that expanded use of alternative financing may lead to reduced levels of OMB and Congressional oversight. The three PMAs argue that alternative financing does not give oversight agencies any fewer opportunities to exercise their oversight responsibilities. Since alternative financing is presented in agencies' budget justification materials, OMB and Congressional oversight equal to that of appropriation requests can still be provided. Planned expenditures, even though not requiring appropriations, would be disclosed in whatever detail Congress requested. PMA customers, who foot the bill for the PMAs' spending, have been, and will continue to, exercise much oversight, as well.

See comment 16.

Discussion of Charging Rates Based on Competition is Misleading. One option discussed in the draft report is to have the PMAs price their power competitively, based on what the market will bear. This option is presented because that is the direction the electric utility industry is moving as the industry restructures. However, the greatest impetus for competition in the industry is coming from consumers (usually large industrial customers) and regions that expect competition to reduce their power rates. As noted in the draft, competitive pricing will most likely lead to higher rates for PMA customers. Hence, it is misleading to use the trend towards competitive pricing as the only rationale for PMAs to pursue this option.

See comment 17.

Discussion of Cost Reallocation Should Cover Equity Concerns. Equity issues were discussed at various points in the draft report, but not in the sections on cost reallocations (See pp. 60, 73-74). The PMAs believe the equity of certain project beneficiaries (e.g. power customers) having to repay more than their fair share of multipurpose costs also needs to be addressed.

See comment 18.

Corporatization Is Not Western Policy. The draft report cites officials from Western's Colorado River Storage Project Customer Service Center as suggesting corporatization for their marketing program. It should be clarified that it is not Western's policy to support corporatization of this marketing program at this time.

See comment 19.

Corporatization May Not Involve Lessened Oversight. The draft report asserts that a government corporation will necessarily receive reduced oversight from Congress and other outside entities. The PMAs believe this will depend on what oversight Congress chooses when it establishes the new corporate entity. Oversight may or may not be lessened, depending on the amount of oversight Congress retains for itself or outside oversight agencies.

See comment 20.

Previous PMA Comments on Divestiture Need Inclusion in Chapter 3. In March, 1997, GAO issued a report entitled, Federal Power: Issues Related to the Divestiture of Federal Hydropower Resources (GAO/RCED-97-48). The three PMAs provided extensive comments on that report that were printed at pages 96-101. To the extent Chapter 3's discussion in the draft report relies upon the earlier report, the PMAs ask that our previous comments again be considered. The PMAs are pleased with the draft report's recognition that Federal water projects serve multiple public purposes that need to be carefully considered in any divestiture analysis.

See comment 21.

Any Further GAO Analysis of Divestiture Should Consider Quantifying the Transaction Costs. Chapter 3 presents complications associated with divestiture of Federal hydropower assets.

These complications would impose a cost on the Federal government, in many cases. To the extent that GAO conducts further analyses of this option, any quantification of the benefits of divestiture (e.g. sales revenue) should be matched by a quantification of these transaction costs.

POLICY COMMENTS ON APPENDIX V: "PROJECTS AND RATESETTING SYSTEMS OF THE THREE PMAs WHERE THE FEDERAL INVESTMENT IS AT RISK"

See comment 22.

Southeastern Believes the Amount of Potential Loss at the Russell Project Is Too Large. The draft report states that if the Russell pumping units are never allowed to operate commercially, the entire $518 million investment will probably be unrecovered. Southeastern believes that some portion of the $518 million investment will be recovered even if the units are never commercially operated.

See comment 23.

Southwestern Expects Truman Project Pumpback Units to Operate. The draft report claims it is unlikely for these units to be placed in commercial operation. Southwestern disagrees, believing the units will become operational. Nevertheless, even if the units are never operable, Southwestern could add the power-related costs of this investment into its repayment study and still sell its power at a competitive rate. Hence, the risk of loss is "remote" in our opinion.

See comment 24.

Western Believes Risk of Central Valley Project Loss Is Overstated. The draft GAO report concludes that it is "reasonably possible" that some costs allocated to power in the Central Valley Project (CVP) will not be repaid. Western believes the risk of nonpayment is "remote."

According to the Federal Energy Regulatory Commission in their January 8, 1998, order approving new, lower CVP power rates, Western customers had repaid 71.8 percent of the CVP's power investment. FERC compared this actual repayment against the 50 percent that would have been repaid under a compound interest amortization schedule, and concluded past rates were adequate. FERC went on to say, "...the revenues collected under the proposed [current] rates will be sufficient to recover WAPA's costs and the remaining Federal investment." Specifically, the power repayment study used to develop the current rates already included assumptions about the environmental impacts the draft report cites as threatening the CVP's repayment.

See comment 25.

In addition, Western's original comments on the risk of CVP nonpayment found on pages 153-154 of GAO/AIMD-97-110A continue to apply.

See comment 26.

Risk of Loss at Washoe Project is "Remote". As we commented on GAO/AIMD-97-110A, Western staff judge the probability of a loss at the Washoe Project to be "remote" because Western is proposing to blend Washoe power with CVP power after the year 2004 to ensure Washoe's repayment. The impact of including Washoe repayment in CVP rates is negligible.

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

Sincerely,

Jack Dodd

R. Jack Dodd
Acting Assistant Administrator

Enclosure

GAO's Comments

The following are GAO's comments on the letter dated January 28, 1998, from the Department of Energy.

1. We do not believe that we have overstated the magnitude of the net financing costs. Our methodology for determining such costs is discussed below under comment 7. Also, our evaluation of comments about the recovery of unrecovered costs is discussed below in comments 22, 23, and 25. We do not believe that we have overstated the risk of nonrecovery of some of the federal investment related to hydropower projects. Our evaluations of risk levels are discussed under comments 23, 24, and 25. We did not add language acknowledging the use of current interest rates on federal investments since 1983 because that fact was already contained in chapter 2 of our draft report. We added language to discuss the PMAS' proposed actions to recover additional costs to chapters 2 and 3 and appendix V. We also added language to chapters 1 and 3 to describe the PMAS' efforts to reduce costs or otherwise improve their business practices.

2. We incorporated changes in the body of the report and to the executive summary as appropriate.

3. We expanded our discussion of the role of public power in chapter 1 to include DOE's views on public power's role in providing competition for IOUS and in charging power rates against which the power rates of the IOUS can be compared. We also revised our discussion of the mission of federal power in the executive summary to clarify that rural electrification was not the sole purpose of selling federal power.

4. We added to chapter 1 a description of the PMAS' recent actions to file tariffs relative to FERC Order 888.

5. We added information on actions the PMAS have taken to enhance their competitiveness, including cost reduction efforts by Southwestern and Western, to chapter 1. These actions did not change the competitiveness of the PMAS enough to warrant changing our assessments of risk.

6. We disagree with DOE's comments on the magnitude of net financing costs and the degree of risk. Its comments on net costs are discussed below in comment 7. Its comments on the degree of risk are discussed in comments 23, 24, and 25.

7. In commenting on an earlier GAO product, Southeastern, Southwestern, and Western ("the three PMAS") as well as Bonneville disagreed with our estimate of the net financing costs. Two broad issues were raised: (1) disagreement with our use of the portfolio methodology for estimating the net financing costs to the federal government for appropriated debt, including the use of the weighted average interest rate on outstanding long-term Treasury bonds, and (2) the assertion that the PMAS' appropriated debt is analogous to a mortgage loan. To calculate the net financing costs to the Treasury under the portfolio method, we obtained the federal government's annual interest income from the PMAS by multiplying the amount of the PMAS' appropriated debt outstanding as of September 30, 1996, by the weighted average interest rate paid by the PMAS. To calculate interest expense for the federal government, we multiplied the amount of the PMAS' appropriated debt outstanding by the average interest rate the Treasury was paying on its portfolio of bonds outstanding at the end of fiscal year 1996—9 percent—which yields an estimate of the amount of interest expense the Treasury must pay on the PMAS' outstanding appropriated debt. The difference between the federal government's interest income and interest expense represents the net financing cost.[1] DOE stated that it believes that the use of the portfolio methodology assumes that both the PMAS' interest rate and the Treasury's cost of funds are variable, so that the cost difference on any individual investment varies from year to year. It stated that this is equivalent to assuming that the PMAS' appropriated debt should be refinanced annually. DOE stated that comparing the interest rates assigned to PMA financing with the Treasury's rates in the years the financing was provided (loan-by-loan methodology) would be a more accurate way of determining the net financing cost. DOE and Bonneville also disagreed about how we estimated the net financing costs on outstanding appropriated debt by using the interest rate on the Treasury's outstanding bond portfolio.

As discussed in GAO/AIMD-97-110A, we define the net financing cost to the federal government as the difference between the Treasury's borrowing cost and the interest income received from RUS' borrowers, the PMAS, and TVA. Our basic methodology is to determine whether the federal government received a return sufficient to cover its borrowing costs and, if not, to estimate the net financing cost. RUS, the PMAS, and TVA had several forms of federal debt outstanding at September 30, 1996. Each of these forms of federal debt had different terms and thus required us to apply variations of our basic methodology in assessing whether a net financing cost existed and, if so, estimating the amount.

[1]For a further discussion of PMA financing, see GAO/AIMD-96-145.

We continue to believe that, for the PMAs' appropriated debt, the portfolio methodology best captures the combined impact of the four distinct aspects of the net financing cost that we identified: (1) the difference between the PMAs' borrowing rate and the Treasury's borrowing rate for securities of similar maturity at the time the appropriation was made, (2) the PMAs' ability to repay the highest interest rate debt first, (3) the interest rate risk arising from the Treasury's general inability to refinance or prepay outstanding debt in times of falling interest rates, and (4) the difference in the maturities of the three PMAs' and Bonneville's appropriated debt and the Treasury's bonds. We believe that the suggested loan-by-loan methodology is limited in that it captures only that portion of the net financing cost arising from the interest rate spread and not the other three integral aspects of that cost.[2]

8. We revised the executive summary and chapter 2 to state that maintenance problems differ by location within the operating agencies.

9. We acknowledge that planning and budgeting problems do not originate solely within the operating agencies; rather, they are endemic of the federal budgeting process government wide. However, we believe that the operating agencies' lengthy and complex processes contribute to the overall problem. We clarified chapter 2 accordingly.

10. We acknowledge that average revenue per kWh (total revenues/total electricity sales) is an imperfect indicator of electricity rates because it combines the costs of several types of services, such as capacity, peak service, and off-peak service. However, for our analysis, it is a strong, broad, indicator of the relative power production costs of the PMAs compared to IOUs and publicly owned generators. For example, TVA's 1997 business outlook presents the agency's goals for competitive power rates in terms of overall, systemwide rates. And, in responding to our August 1995 report,[3] TVA's consultant used this measure in assessing TVA's competitiveness. Also, the fiscal year 1995 annual reports for Southeastern, Southwestern, and Western—our primary data sources for PMA sales data—reported each customer's total electricity purchases and revenues. They do not present the data by type of service. The same is true for the non-PMA wholesale data that we received from EIA. Moreover, we

[2]A more complete discussion of our methodology is contained in GAO/AIMD-97-110.

[3]GAO/AIMD/RCED-95-134.

believe that average revenue per kWh is a proxy for rates that is widely used in the industry.[4]

11. We added to table 2.1 information reflecting the comments provided on the risk of project cost recovery, especially the statements about recovery of costs for units that are not allowed to operate or to operate as originally designed. However, we believe the recovery of costs from nonoperating units overlooks the policy guidance contained in DOE Order RA 6120.2, which indicates that if the nonoperational units are not placed into commercial service, the power customers will not be required to repay the investment.

12. We acknowledge that DOE disagrees with some of the findings in previous GAO products. We do not agree with its conclusion that our evaluations are somewhat inaccurate and incomplete. Our responses to many of DOE's specific comments on issues raised in past reports are contained in this appendix. We have added detailed information throughout our final report to make our current report more complete.

13. We agree that the value of specific federal assets considered for any divestiture can vary widely based on the assumptions used. Our report contains a discussion of the liabilities, assets, and restrictions that may be retained or transferred by the government upon any divestiture. Our report concludes that these factors would affect the price the government would obtain for its assets.

14. We acknowledge that much federal investment is regional in nature and believe that this condition leaves such investment open to debate by the Congress and others. We also acknowledge that an examination of topics such as why federal power is provided in certain regions of the nation, transmission limitations, and the regional equity of all federal government spending could be undertaken. Such analysis, however, is outside the scope of this report.

15. We agree that alternative financing does not necessarily reduce the opportunities for oversight by the Congress and others. We added language to chapter 3 describing congressional latitude in fostering opportunities for oversight under expanded use of alternative financing.

16. We disagree with DOE's conclusion that we present the option of charging rates based on competition only because of the electric utility

[4]More discussion of our use of average revenue per kWh is contained in GAO/AIMD-97-110.

industry's trend toward competitive pricing. We agree that many consumers expect lower prices as a result of a restructured electrical industry and that competitive pricing will most likely lead to higher prices for most PMA customers. After the wholesale market restructures, competitive rates may still be higher than the rates the PMAS currently charge.

17. We expanded our discussion of cost reallocation in chapter 3 to recognize that an equity issue exists concerning power purchasers having to repay costs that are not related to power.

18. We revised chapter 3 to state that Western does not support corporatization of that marketing program at this time.

19. We revised the executive summary and chapter 3 to include the comment that the degree of oversight following any corporatization depends on the particular arrangements chosen by the Congress for itself or outside oversight agencies.

20. We added to chapter 3 additional language concerning Native American interests in rights-of-way based on this review.

21. We agree that divestitures would include federal transaction costs. If we are requested to analyze the costs of quantifying the benefits and costs associated with divesting the federal hydropower assets, we would consider quantifying the transaction costs.

22. DOE stated that some portion of the $518 million will be recovered even if the pumping units are never commercially operated. We added to table 2.1 and appendix V DOE's assertion that some unspecified portion of the $518 million investment in pumping units at the Russell project will be recovered even if the units are never commercially operated. However, we added language that we believe this assertion by the PMAS overlooks the policy guidance contained in DOE Order RA 6120.2, which indicates that if the nonoperational units are not placed into commercial service, the power customers will not be required to repay the investment.

23. We added to table 2.1 and appendix V DOE's assertion that Southwestern can add to its power repayment study the power-related costs of pumpback units at the Truman project even if the units are never operable. We also added, however, that we do not believe that a change in

risk category is appropriate until these costs are actually added to Southwestern's repayment study.

24. We added to chapter 2 and appendix V language describing the January 1998 decision by FERC that approved the lowering of rates for power marketed from the Central Valley Project (CVP). We disagree that this action is sufficient to warrant an upgrading of the risk category to "remote."

25. We reviewed the comments provided for an earlier GAO report, GAO/AIMD-97-110A, and believe that our earlier evaluations are accurate. For example, we continue to (1) agree that CVP was able to meet its repayment obligations in fiscal year 1996, (2) believe that the Central Valley Project Improvement Act may adversely affect the availability of water for power generation,[5] and (3) conclude that the appropriate category of risk for CVP is "reasonably possible." Assignment of this risk category is the result, in part, of the uncertain potential reductions in the Trinity River's water flows available to the CVP, as DOE noted.[6]

26. We disagree that the risk of nonrepayment for the Washoe Project is remote. DOE states that Western staff are proposing the blending of the costs of power from the Washoe Project with the costs of power from the CVP after 2004. This proposal was noted in appendix V of our draft report. We continue to believe that the risk of nonrecovery is probable, if this proposal is not implemented, and that the risk category improves only to reasonably possible, if the proposal is implemented. We believe that the risk associated with a blended rate is not remote because, as we state in appendix V, the CVP itself faces challenges in remaining competitive.

[5]For example, according to the Bureau's comments on the draft report, managing 800,000 acre-feet of water within the CVP to benefit the environment could reduce hydropower generation by 5 percent.

[6]A more detailed discussion of the risk of nonrecovery of the federal investment associated with the CVP is contained in GAO/AIMD-97-110A.

Comments From the Department of the Interior

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

United States Department of the Interior

OFFICE OF THE SECRETARY
Washington, D.C. 20240

FEB 3 1998

Mr. Victor S. Rezendes
Director, Energy, Resources,
and Science Issues
General Accounting Office
441 G Street, N.W.
Washington, D.C. 20548

Dear Mr. Rezendes:

Enclosed are comments on the General Accounting Office draft report entitled "Federal Power: Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry" (GAO/RCED-98-43).

Provided are a number of general and specific comments that are intended to clarify the respective roles and relationship between the Bureau of Reclamation and the power marketing administrations and to clarify the statutory requirements regarding the management of Reclamation facilities for multiple purposes.

See comment 1.

Of particular concern are the comments in the report that Reclamation's availability factor indicates that Reclamation has not adequately maintained and repaired its powerplants. The proper operation and maintenance of Reclamation's power facilities has been and remains a high priority with Reclamation. It is important to note that because Reclamation projects with power generation are multipurpose, the availability rates alone are not an indication of inadequate maintenance, but a reflection of statutory priorities. Reclamation's National Performance Review Power Management Laboratory provided an intensive review of all aspects of Reclamation's power program including an aggressive benchmarking effort. The benchmarking program compared Reclamation's power operation and maintenance program performance against 11 industry leaders, including the best public and private generators with hydropower facilities in North America. This work, which was a recipient of the Vice President's *Hammer Award* for excellence in reinventing Government, determined that Reclamation's performance compared well to others' in the hydropower industry.

We appreciate the opportunity to review the draft report and to comment on the subject matter. However, the very short review time requested precluded our providing the comprehensive review that this subject deserves. We hope you will find the enclosed comments to be of assistance. If you have any questions or require additional information, please contact Luis Maez at (303) 236-3289, extension 245.

Sincerely,

Patricia J. Beneke

Patricia J. Beneke
Assistant Secretary
for Water and Science

Enclosure

Bureau of Reclamation
Comments on Draft GAO Report

Federal Power: Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry
GAO/RCED-98-43

General Comments

See comment 2.

1. The report makes specific mention of the age of the powerplants that are operated by the Bureau of Reclamation (Reclamation) and states, ". . . Bureau's and the Corps' planning and budgeting processes do not always provide funding to repair the Federal power assets when the funding is needed, causing some repairs to be deferred and also causing the power plants to become less available to provide power." The options in the report summary failed to identify the funding arrangements the agencies developed to augment the budgetary reductions such as the alternative financing arrangements currently in place with the Parker-Davis Project preference customers and the Central Valley Project (CVP) preference customers. These arrangements provide a source of funding to Reclamation with the only constraint being that Reclamation expends the funds on activities for which they were provided.

See comment 3.

2. The report cites Reclamation's budget reductions resulting in insufficient resources to fund hydropower repairs as an example of management deficiency. The report fails to look at actual expenditures as a true indicator of Reclamation's operation and maintenance performance. With the exception of certain projects, Reclamation's budget is not hydropower specific. While the budget is formulated too far in advance to accurately plan for some conditions, Reclamation has been able to adequately manage the appropriations to ensure necessary repairs are made to maintain a safe, reliable energy resource.

See comment 4.

3. The fundamental premise in a significant part of this report is that Reclamation and the Corps of Engineers (Corps) have not adequately maintained their powerplants. It also draws the conclusion that Reclamation's generation availability, which is lower than the industry average, is indicative of Reclamation's deferred maintenance practices. Under Reclamation procedures, Reclamation does not defer critical maintenance needed to protect public safety. Similarly, Reclamation does not defer maintenance that could result in disruptions in delivering water and power. While improvements to Reclamation's power program have been identified as part of Reclamation's National Performance Review Power Management Laboratory, to date, unit reliability (as a function of being able to operate units to meet water release schedules and electric system on-peak demand) remains high. It is important to note that Reclamation's availability factor is principally a function of the legal constraints due to the multipurposes authorized by the Congress. Reclamation projects with power facilities were authorized and are operated to meet multiple public purpose objectives. Reclamation facilities were constructed primarily to meet irrigation requirements with power production being a secondary purpose. Therefore, availability rates are not necessarily indicative of whether a facility is maximizing power production. Reclamation has not bypassed significant amounts of water due to inability to generate when the water is released for irrigation or municipal purposes unless scheduled long term maintenance, such as a unit rewind, uprate, or overhaul, was underway. Reclamation's units have been available when needed to generate power with available water.

2

4. The report should indicate that Reclamation and the Corps have entered into long-term agreements with the Bonneville Power Administration (BPA) to fund capital improvements and operation and maintenance costs associated with power at its powerplants in the Pacific Northwest. These agreements address the planning and budget problems associated with the appropriations process allowing more accurate and timely planning and permitting operations in a more businesslike manner. These agreements have resulted in reducing the appropriations requirements by approximately $45 million for Reclamation's Pacific Northwest hydropower projects.

See comment 5.

5. The executive summary implies that all power generated by Reclamation is marketed by the power marketing administrations (PMAs). Power generation is a secondary purpose of the facilities, and the report needs to clarify that Reclamation uses from 5 to 10 percent of the power it produces to meet statutory and contractual obligations to project users and other purposes. Only the remaining power, which is considered surplus, is marketed by the PMAs.

See comment 6.

6. The "businesslike manner" prescribed in this report is to maximize revenues to recover investments which is in accordance with investor owned utility (IOU) business practices. It would seem more reasonable to examine the agencies' "businesslike manner" with respect to the mission and goals of the agencies. Unlike IOU facilities which are constructed to produce power to create profits, Reclamation's and the Corps' power facilities were created to aid in the financial undertaking of Federal water projects. Power is considered a byproduct of Federal irrigation projects. The Federal water projects are operated to serve purposes other than maximizing the power revenues to recover investment. Federal power generation is maximized within the operating constraints imposed by the goals of the respective projects. Reclamation law requires that Reclamation operates the plants in a manner consistent with sound business practices. However, it must be recognized that this is often constrained by statutory requirements and not by a failure on the part of the operating agency to operate using sound business practices. This is an important distinction. The implication in the report is that Reclamation chooses to operate in this "unsound manner" which is not true. The report cites several examples where costs are not recovered including the Pick Sloan Missouri Basin Project and the Shasta Dam. In both cases, Reclamation operates the facilities in a specific manner as mandated by the Congress.

See comment 7.

7. The Energy Policy Act of 1992, Federal Energy Regulatory Commission Order 888, the Final Rule, separates generation from transmission and is the core of the electric industry restructuring. The options in the report diverge from this fundamental policy in recommending merging the agencies responsible for transmission with the agencies responsible for generation.

See comment 8.

8. The report references the Corps and Reclamation together when describing operating agencies and project operations and management. The report needs to separate the Corps and Reclamation as they are managed by different Secretaries and governed by different standards, policies, laws, and regulations.

See comment 9.

GAO's Comments

The following are GAO's comments on the Department of the Interior's letter dated February 3, 1998.

The Department of the Interior (Interior) provided us with comments that were intended to clarify the respective roles and relationship between the Bureau of Reclamation and the PMAS and to clarify statutory requirements for the management of the Bureau's facilities for multiple purposes.

1. In its letter, Interior stated its concern that our report concluded that the availability factor for the Bureau's power plants is lower than an average for an industry benchmarking group because the Bureau has not adequately maintained and repaired its power plants. In response to this comment, we revised the report, including the executive summary, to state that the federal planning and budgeting processes, as implemented by the Bureau, do not allow for timely funding of needed repairs to the Bureau's power plants. This situation, in turn, has contributed to the decreased availability of the Bureau's power plants. We believe this revision is supported by the Bureau's own performance data for its power plants and by the fact that the Bureau is negotiating and has negotiated arrangements with Western and Western's preference customers for those customers to provide advanced funding of needed repairs. This arrangement would allow funding to occur when needed to pay for repairs to the power assets.

In addition, while acknowledging the importance of irrigation and other multiple purposes as key factors in managing the Bureau's water and power resources, we disagree that the need to balance multiple purposes would necessarily decrease the availability of the Bureau's power plants to generate power. In this regard, the availability factor does not measure how much water is diverted for multiple purposes. This factor simply expresses the amount of time a plant is available to generate power divided by the total number of hours in a time period. In addition, many other federal and nonfederal power plants also generate power subject to multiple uses of the water. Yet the Bureau's availability factor was below that of this comparison group.

Interior also provided us with general and detailed comments. Our responses to the general comments are contained below. The detailed comments were of a technical or editorial nature, which we addressed as appropriate in the report.

2. The report currently discusses alternative financing arrangements in the Bureau's Central Valley Project (CVP) and Loveland projects. We expanded

our discussion of these arrangements in the executive summary, chapter 2, and chapter 3.

3. We disagree with Interior's statement that we characterize insufficient resources to fund repairs as a sign of "management deficiency." We do not characterize the Bureau's resource levels in this fashion. Rather, we state that the budget process used by the Bureau, the Corps, and other federal agencies is not always appropriate for a commercial activity. In the case of the Bureau and the Corps, it does not deliver funding on a predictable, timely basis when it is needed to pay for repairs to the federal hydropower assets. We modified the report to emphasize that the planning and budgeting processes are causes for the relatively low availability factor of the Bureau's power plants.

We also disagree with Interior's statement that the Bureau has been able to adequately manage the appropriations to ensure that necessary repairs are made. The Bureau's staff at the regional level, Western's staff, and Western's preference customers contend that obtaining funding for necessary repairs to the Bureau's power assets is sometimes difficult and unpredictable, amid shrinking budgets. For example, the General Manager of the Northern California Power Agency, on March 19, 1996, testified before the House Subcommittee on Water and Power that:

> ". . . OM&R [operation, maintenance, and rehabilitations] problems have occurred in the CVP and, assuming the discretionary spending portion of the federal budget continues to shrink as agreed by the Congress and by the Executive Branch, we will get worse with age. However, in the case of the CVP's Shasta Dam, a creative customer-financing solution has been implemented to the aging problems with three of the five generators in the dam."

In another example, a study conducted by Northern California Power Agency, the Sacramento Municipal Utility District, the Bureau, and Western in September 1996 details shortfalls within the CVP in the maintenance and operating condition of the CVP's power plants. The report, based on walk-through inspections of the Bureau's power plants by teams of engineers from the Bureau, Western, and the Northern California Power Agency, states in its executive summary, among other things,

> "The majority of the original CVP facilities that are operated and maintained by Reclamation [the Bureau] were constructed over a period from the mid 1940s to the late 1970s. A significant amount of plant equipment is obsolete and replacement parts are no longer available. Other equipment is one-of-a-kind type of hardware or built by vendors who have moved into new technology or are no longer in business. Much of the original equipment

and systems are well worn and require an abnormal level of maintenance to keep the facilities in operation. Several generator units have been or are being upgraded, but the majority of the units are long into their life cycle and soon will need attention to continue at rated operation."

In addition, according to the Northern California Power Agency's General Manager and officials from Western's and other PMAS' customer organizations, shrinking budget levels and the unpredictability of funding levels have led to alternative funding methodologies whereby PMA customers donate funds to pay for needed repairs, upgrades, and rehabilitations. In our view, such measures are becoming increasingly popular among the operating agencies, the PMAS, and their customers in order to ensure that the federal power resource is adequately maintained and repaired and the PMAS' preference customers receive the power in a manner to which they are accustomed.

4. We believe that the Bureau operates and maintains its power plants within the constraints posed by its budget and is trying to do so in a more efficient, businesslike manner. We further agree, as previously discussed with Bureau officials, that the Bureau has no formal policy of deferring maintenance of its power assets. In this regard, we revised the report where appropriate.

As stated before, we disagree that the need to balance multiple purposes would necessarily decrease the availability of the Bureau's power plants to generate power. In this regard, the availability factor does not measure how much water is diverted for multiple purposes. This factor simply expresses the amount of time a plant is available to generate power divided by the total number of hours in a time period. In addition, many other federal and nonfederal power plants also generate power subject to multiple uses of the water. Yet the Bureau's availability factor was below that of this comparison group.

5. Interior provided information on interagency arrangements to fund O&M for federal power plants in the Pacific Northwest. We revised our report as suggested.

6. According to Interior, the executive summary implies that all power generated by the Bureau is marketed by the PMAS, ignoring the fact that power generation is a "secondary purpose" and the Bureau uses 5 percent to 10 percent of the power for project purposes. The PMAS market the remaining power. We agree with these statements and added language to

the executive summary and chapter 1 to recognize that the PMAS market only the power that remains after it has been used for project purposes—for example, to pump water for irrigation.

7. According to Interior, our report prescribes a "businesslike" approach to the PMAS' rate-setting practices that would maximize revenues to recover investments, much like IOUS set rates. Interior adds that the rate-setting practices of the PMAS should be examined in light of the multiple purposes served by the Bureau's water projects. Interior stated that power generation is a byproduct of the federal irrigation projects. It also stated that power generation, along with power revenues, is maximized subject to the multiple purposes of the projects. Moreover, power revenues are intended to pay for the features of the projects, according to Interior.

We disagree with Interior's comments that the report prescribes an approach to the PMAS' rate-setting practices that would maximize revenues to recover investment. In fact, the report makes no recommendations that can be construed as "prescribing" any one approach. Rather, it presents options that policymakers may consider to better capture the federal investment in power-related facilities as well as those federal investments allocated to power for repayment. In describing these options, we took great care to ensure that we reflected many of the options' pros and cons. For example, we state that the PMAS could opt to increase their power rates to repay the federal investment faster. However, to counterbalance that advantage, we carefully state that any movement by the PMAS to increase their rates could make the PMAS' power over-priced in evolving competitive markets. Overpriced power would be difficult to sell, thus jeopardizing the repayment of the federal investment. In addition, the report recognizes that power sold by the PMAS is generated and marketed subject to the multiple purposes of water projects. The report also states that power is used for project purposes and also recognizes that power revenues pay for nonpower features—for instance, we discuss the concept of aid-to-irrigation and that power revenues are scheduled to repay about 70 percent of the capital costs associated with irrigation projects. However, on the basis of the Bureau's comments, we revised the executive summary and chapter 1 to emphasize the first use of power for project purposes—for example, irrigation.

Interior also stated that our report characterizes the Bureau as operating in an unsound fashion because all costs are not recovered through the PMAS' rates. We disagree with this statement. Nowhere does the report state that the Bureau operates its projects in an unsound fashion. In fact, the report explicitly states that the PMAs are following applicable laws and regulations in setting rates and recovering costs. For example, in our discussion of cost recovery within the Pick-Sloan program, chapter 2 and appendix V clearly state that suballocated costs[1] will not be recovered absent congressional action because the current repayment methodology and suballocation amounts are based on federal statutes. In connection with the Shasta Project, the executive summary clearly recognizes that "the 1991 Energy and Water Development Appropriations Act specified that these costs not be allocated to power for repayment through PMA customers' electric rates." This point is made in chapter 2, also. The report does not imply in either the Pick-Sloan or the Shasta case that the agencies are intentionally deferring cost recovery through power rates.

8. We disagree with Interior's comment that the options in our draft report recommended diverging from the fundamental policy that encourages or requires the separation of various electric utility aspects and services. First, our draft report contained no recommendations. Second, our draft report clearly stated, "Although the electric utility industry is now unbundling its services, depending on how a government corporation was structured, the generation, transmission, and marketing aspects could be put under one agency, possibly reducing overhead." Therefore, we made no change to the final report.

9. We agree that the Bureau and the Corps have separate organizations, management, missions, standards, policies, laws, and regulations. However, no changes are needed to the report. We only refer to the Corps and the Bureau together primarily when addressing their common role as operating agencies. Where appropriate, for example, when addressing the availability factors of the Bureau's and the Corps' power plants, we differentiate between the agencies.

[1]For a further discussion of suballocated costs, see GAO/T-RCED-96-142.

Comments From the Department of Defense

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

DEPARTMENT OF THE ARMY
U.S. Army Corps of Engineers
WASHINGTON, D.C. 20314-1000

REPLY TO
ATTENTION OF:

29 JAN 1998

Audit Office

Comptroller General
General Accounting Office
ATTN: Ms. Peg Reese, RCED
441 G Street, N.W.
Washington, D.C. 20548

Dear Sir:

Enclosed is the official command response to the draft report on subject audit.

Sincerely,

Otis Williams
Colonel, Corps of Engineers
Deputy Chief of Staff, Operations

Encl
as

Federal Power: Options for Selected Power
Marketing Administrations' Role in a Changing Electricity Industry

1. The following are comments on the subject draft GAO report.

2. Executive Summary: There is a great deal of information left out of the Executive Summary. It is important that the following items be discussed in the summary and not buried in one of the appendices.

a. Page 4.

See comment 1.
Now on p. 3.

(1). Purposes. GAO's premise is not totally correct. While one of the original purposes of Federal hydropower was to help electrify rural America, the Flood Control Act of '44 established cost recovery as the primary purpose. In general, hydropower is a secondary purpose of Federal water resources projects. Flood control, navigation and irrigation are the primary purposes.

See comment 2.
Now on p. 4.

(2). Pension and Post-retirement Benefits. Prior to FY 95 these costs were not available to the Federal power agencies. It was only when OPM stopped budgeting for these costs that Federal agencies became responsible for these additional expenses. GAO in this report and previous documents make it sound as if the Federal Power Agencies were knowingly avoiding these costs.

See comment 3.
Now on p. 4.

(3). Excluded projects. The last line of the last paragraph should be changed from "...(3) the construction of selected... projects." to "(3) the construction of a very few... projects."

See comment 4.
Now on p. 5.

b. Page 6. Units 1 - 4 at the Russell Project are full operational, it is only the pump back units (5 - 8) that are subject to the court action. At Truman the turbines are being rebuilt due to manufacturer's defects. By mid FY99, all Truman units will be rehabilitated and available for conventional operation. How SEPA and SWPA decides to enter them into the rate base is not under the control of the Corps.

See comment 5.
Now on p. 7.

c. Page 8. GAO has failed to use updated performance data that has been furnished by this office. While the Corps' plant availability did "bottom-out" at 87.89% in FY95, it has increased to 88.43% in FY96 and 89.04% in FY97. More important is the fact that the forced outage percentage has gone from 5.98% in FY95, 5.04% in FY96, to 4.44% in FY97. This 25% reduction in unplanned outages is a significant indicator that the Corps has control of their program. GAO has an obligation to provide credit to agencies when improvements are made, just as when there are problems. See enclosed charts.

See comment 6.
Now on pp. 7 and 8.

d. Pasze 9. There is no mention of the Corps major rehabilitation program, which addresses some of the problems associated with the appropriations process. For the period from FY 93

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Marketing Administrations' Role in a Changing Electricity Industry
Page 2

through FY 07, there is approximately $450 million in hydropower work committed under the Construction General appropriation.

See comment 7.
Now on p. 10.

e. Page 12. None of the options need to reduce the oversight by either the Congress or the Administration. The oversight issue is one that is often raised by the proponents of privatization.

See comment 8.
Now on p. 11, footnote 13.

f. Page 13. Note 12. Power is rarely sold from a specific project, rather it is a blended rate for a specific system. While a project may not be pulling its weight because of outages or a bad water year, the system will continue to be economical.

See comment 9.
Now on p. 29.

g. Chapter 1, Page 32. There is a word missing in the next to the last sentence in the second paragraph. "Public utilities have to file [?] offer their services..."

h. Chqpter 2:

See comment 10.
Now on p. 39.

(1). Page 45, Employee Benefits. There needs to be some background as to why this issue has come to light. There is no mention of SFFAS-5, dated December 20, 1995, which established the need for accounting and reporting for liabilities of employee retirement costs. It appears from this draft and previous GAO reports that the PMA's were doing something inappropriate.

See comment 11.
Now on p. 39.

(2). Page 45 - 46, Construction Costs. The costs associated with Richard B. Russell units 5 - 8 are not included in the power rates because court injunctions have delayed commercial operation. Please clarify that if a commercial power producer was in the same position, they would not be allowed to include these cost in their power rate case. The implication of this paragraph is that SEPA is doing something wrong.

1. Chapter 3.

See comment 12.
Now on p. 54.

(1). Page 63, Capital Planning. Beginning in 1990, the Corps began developing guidance for major rehabilitation of navigation and hydropower projects under the Construction General Appropriations. These rehab projects compete as new starts. There are now 10 power projects approved for funding for FY 93 through FY 07, which total approximately $450 million. For the most part Construction General funded projects are multi-year and do not have to be rebudgeted each year.

See comment 13.
Now on p. 55, footnote 9.

(2). Page 64, Note 8. While the Corps is not covered by the USBR Contributed Funds Act, Army General Counsel has determined that we can receive funds from the customer, with certain restrictions.

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Marketing Administrations' Role in a Changing Electricity Industry
Page 3

See comment 14.
Now on p. 57.

(3). Page 65, Last paragraph. The memo states that it would be desirable to have specific legislation to clarify the authorities, but that the law allows certain contributions.

See comment 15.
Now on p. 70.

(4). Page 82. Divest... Assets. Most discussions of divestiture fail to recognize that hydropower is not the primary purpose for these Federal water resources projects. The transfer of liability from the Government to the new owners is also not explored in any depth.

See comment 16.
Now on p. 71.

(5). Page 83, Accommodate Multil2le Purposes.... The first sentence should read ***"Except for a veryfew cases,*** federal hydropower projects have multiple purposes..."

See comment 17.
Now on p. 74.

(6). Page 87, Trade-off... If the Government wants to get out of the hydropower business, it must get completely out of water resources. If the powerhouses are sold and the Government is still operating the remainder of the project, the tax payer's future liabilities could be great.

See comment 18.
Now on p. 81.

(7). Page 96. There is a concern that GAO is energy pricing. With the unbundling of services, the future value of capacity may be proportionally higher than energy. This will be an additional impact on the preference customers.

See comment 19.
Now on p. 119.

j. Appendix V, page 148. The 53 MW capacity shown for Harry S. Truman may be wrong. The nameplate of the project is listed a 160 MW. Three units are rehabed and in service (another will return on 28 January 1998 and late in February 1998); the last unit will be completed by February 1999.

GAO's Comments

The following are GAO's comments on the U.S. Army Corps of Engineer's letter dated January 29, 1998. The Corps provided GAO with detailed, technical, and editorial comments in response to our report.

1. In connection with the executive summary, the Corps noted that helping electrify rural America was only one of the purposes of selling federal power and that cost recovery was the primary purpose of generating hydropower. The Corps added that hydropower generation is generally a secondary purpose in multipurpose federal water resource projects; flood control, navigation, and irrigation are the primary purposes. In response, we clarified the executive summary to better reflect that selling federal power in rural areas is only one of several missions of the federal power program. The executive summary already stated that other purposes exist, such as flood control, navigation, and irrigation. We also revised the executive summary to state that hydropower sold by the PMAS is that which remains after it has been used for project purposes, such as pumping water to the fields being irrigated.

2. The Corps noted that prior to fiscal year 1995, the pension and postretirement benefits of power-related federal employees were not made available to the federal power agencies. However, when the Office of Personnel Management stopped budgeting for these costs, the federal agencies became responsible for them, according to the Corps. The Corps states that the report implies that the federal power agencies were "knowingly avoiding these costs." We disagree with the Corps' assessment and therefore made no revisions to the report. The report clearly states that the federal power agencies are recovering costs "under current federal laws, an applicable DOE order, and repayment practices," and it also notes that the PMAS were generally following applicable laws and regulations in their rate-setting practices.

3. We incorporated the editorial revision suggested.

4. On the basis of updated information provided by the Corps, we revised table 2.1 and appendix V to update the status of repairs made at the Russell and Truman projects.

5. The Corps stated that we did not use more recent data reflecting the improved performance of its power plants. We revised the executive summary and chapter 2 to include this new information.

6. The Corps stated that the report did not mention its major rehabilitation program, which dedicated funding of $450 million through fiscal year 2007 to repair the Corps' power plants. A Corps official attributed part of the improved availability of the Corps' hydropower plants to this program. We revised chapter 2 to include this new information.

7. The Corps remarked that none of our options would necessarily reduce oversight by the Congress or by the administration. We agree and revised the executive summary and chapter 3 to state that the extent of external oversight would depend on how the options are structured and added that this oversight could be provided by the Congress or by the Office of Management and Budget by requiring the power agencies to submit expenditure data.

8. The Corps stated that power is rarely marketed and priced on the basis of one project, but is marketed and priced on the basis of a system. In response, we revised the executive summary to indicate that power is marketed and sold from rate-setting systems.

More importantly, however, the Corps added that even if a project does not "pull its weight," the system overall will continue to be economical. However, we believe that a high cost generating project within a rate-setting system, when combined with such factors as the need to mitigate environmental impacts, can cause rates to increase to levels that equal or even exceed regional market rates for wholesale power. If power rates become uncompetitive, the government's ability to sell its power, and hence to repay its investment, is diminished. For example, the composite rates of the Colorado River Storage Project and Central Valley Project have experienced upward pressures, in part as a result of the need to mitigate environmental impacts, to the point that these projects' rates are approaching regional rates for certain types of power.

9. We made the editorial revision suggested.

10. The Corps suggests that information should be included in the report as to why the issue of recovering the annual costs of pension and postretirement health benefits came to light. In September 1996, a GAO report identified costs incurred by the federal government to generate, transmit, and market power.[1] The issue the Corps referred to came to light

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

because this report found that these costs were not being recovered through the PMAS' rates. Therefore, we did not revise our report.

11. The Corps states that certain costs associated with the Truman project cannot be recovered pending the lifting of a court injunction. The Corps suggests that we revise the report to state that a commercial power producer, in the same position, would also not be allowed to include these costs in its power rate case. We did not revise the report because the ability of an IOU to ultimately include those costs in its rates would depend on the actions of a public utility commission, which would be uncertain.

12. The Corps provided new information about its $450 million major rehabilitation program that we incorporated into chapters 2 and 3.

13. In chapter 3, we included information provided by the Corps that the Army's General Counsel has determined that the Corps can accept funds from power customers, with certain restrictions.

14. The Corps stated that the memorandum from the Army's General Counsel stated that it would be desirable to have specific legislation clarify the authorities but that the law allows certain contributions. We did not revise the report because the text already contained this information.

15. The Corps stated that the report, in its discussion of divestiture, does not discuss the transfer of federal liabilities to new owners. We did not revise the report because it already discussed in depth the multipurpose aspects of water projects and the impact on a divestiture of the need to manage water for these purposes.

16. We incorporated the editorial revision suggested.

17. The Corps stated that if the powerhouses are sold and the government continues to operate the balance of a water project, the taxpayers' future liabilities would be great. We did not revise our report in response to this observation because the report already addressed the trade-offs that would have to be considered by policymakers as they decide whether and how to proceed in a divestiture of the federal hydropower assets.

18. In connection with our discussion of potential rate increases after a divestiture, the Corps stated that the report engages in "energy pricing." The Corps said that as electric services are unbundled, the generating capacity may be more valuable than the electric energy, with an additional

impact on the PMAs' customers. We decline to revise our report because it already recognized in a footnote in chapter 3 that some PMA customers already use the PMAs' power primarily to satisfy demand during peak periods. For these customers, in the event of a divestiture, the impacts on their rates may be higher than if they had not relied primarily on the PMAs' power to serve their demand during peak periods.

19. The Corps provided us with new information on the nameplate capacity of the Truman project and the status of repairs on the project's generating units that we incorporated in table 2.1 and appendix V.

Comments From the Bonneville Power Administration

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

Department of Energy
Bonneville Power Administration
Washington, D.C. 20585

January 27, 1998

In reply refer to: AN

Mr. Victor S. Rezendes
Director, Energy Resource and Science Issues
Resources, Community, and Economic Development Division
United States General Accounting Office
Washington, D.C. 20548

Dear Mr. Rezendes:

The Bonneville Power Administration (Bonneville) appreciates the opportunity provided by the General Accounting Office (GAO) to review and comment on the January 13, 1998 draft report entitled "Federal Power: Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry" (the Draft Report). The body of the Draft Report takes some care to limit its analysis to three Federal power marketing administrations (PMAs), Western Power Administration, Southeastern Power Administration and Southwestern Power Administration. With respect to Bonneville, the Draft Report, in particular draft Appendix III, reiterates the prior view of the GAO that Bonneville imposes substantial "net costs" to the Federal government. This is a position with which Bonneville disagrees.

Bonneville continues to believe that satisfying its current repayment obligations on balance will provide full compensation for the appropriated investments in the FCRPS. GAO's conclusion as to the net costs of Bonneville fails to use a true measure of the interest cost to the Government, ignores recent legislation that confirms Congress's belief as to the adequacy of Bonneville's repayment responsibilities, and underplays the substantial financial implications of the public benefits Bonneville is required to fund. Bonneville's comments on this matter were provided in detail in its response to GAO's report entitled "Federal Electricity Activities--The Federal Government's Net Cost and Potential for Future Losses" (GAO/AIMD-97-110, September 19, 1997).

Thank you for your consideration of the forgoing comments.

Sincerely,

Stephen J. Wright
Vice President
Office of National Relations

GAO's Comments

The following are GAO's comments on the Bonneville Power Administration's letter dated January 27, 1998.

Bonneville repeated several points it had presented in comments on our September 1997 report.[1] Specifically, Bonneville (1) disagreed with our position that its operations entail substantial net costs, (2) reiterated that it continues to believe that satisfying its current repayment obligations on balance will provide full compensation for the appropriated investments of the Columbia River power system, (3) contended that our position on net costs does not use a true measure of the interest cost to the government, (4) stated that we ignore recent legislation that confirms the Congress' belief as to the adequacy of Bonneville's repayment responsibilities, and (5) asserted that we underplay the significant financial implications of the public benefits funded by Bonneville. Our position on these issues is unchanged.

In connection with the first point about net costs, we found in our September 1997 report that Bonneville had incurred substantial debt at below-Treasury interest rates, as shown in several examples in the subject report. We also noted that Bonneville is only required to pay outstanding principal on the year of maturity and that Bonneville is allowed to repay appropriated debt with the highest interest rate first and to keep the appropriated low-interest rate on its books for decades. We also point out that in fiscal year 1996, the Treasury incurred a net financing cost of $377 million as a result of Bonneville's activities. This net negative cash flow to the federal government will continue as long as the appropriated debt and corresponding Treasury debt are outstanding.

We continue to disagree with Bonneville's second point about its current repayment obligations providing full compensation for the appropriated investments of the Columbia River power system. As discussed above, not only do Bonneville's operations entail a net financing cost, but they also incurred net costs related to postretirement benefits for its employees. Our report already acknowledged in chapter 3 that Bonneville plans to begin recovering these costs in fiscal year 1998, with full recovery planned beginning in fiscal year 2002. Consistent with current policies and law, the PMAs do not plan to recover pre-fiscal year 1998 net costs. Bonneville in its comments provided no new information that would cause our position to be changed.

[1] GAO/AIMD-97-110 and 110A.

We also continue to disagree with Bonneville's third point that our position on net costs does not use a true measure of the interest cost to the government. Among other points we made in replying to Bonneville's comments on our September 1997 report, the interest rate that Bonneville is to pay on its appropriated debt under the Omnibus Consolidated Rescissions and Appropriations Act of 1996 supports our position that a long-term Treasury rate is the correct rate to use in our portfolio analysis. Under the act, that interest rate is based on long-term Treasury interest rates.

Bonneville's fourth point is that we ignore recent legislation that confirms the Congress' belief as to the adequacy of Bonneville's repayment responsibilities. We have no way of ascertaining the Congress' beliefs about the adequacy of Bonneville's repayment responsibilities. Moreover, reporting on, evaluating, or commenting on the congressional view was beyond the scope of this review. Therefore, we declined to revise the report.

Bonneville's fifth point is that we underplay the significant financial implications of the public benefits funded by Bonneville. We decline to revise the report in response. The scope of this assignment did not include examining the public benefits that Bonneville and the other PMAS provide to their respective regions. However, it should be noted that the report states that water projects entail a number of multiple purposes, and hence benefits to the public, such as providing for navigation, flood control, and irrigation. The report also notes that in the event of a divestiture, these purposes may continue as federal functions—a factor that would have to be considered by policymakers in deciding if and how to divest the federal hydropower assets.

Comments From the Federal Energy Regulatory Commission

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

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D. C. 20426

January 26, 1998

Mr. Victor S. Rezendes
Director of Energy, Resources, and
Science Issues
U.S. General Accounting Office
441 G St., N.W.
Rm. 2T23
Washington, D.C. 20548

Dear Mr. Rezendes:

Enclosed is the copy of the draft report Federal Power: Options for Selected Power Marketing Administrations' Role in a Changing Electricity Industry (GAO/RCED-98-43, Code 141044) which your office provided to the Commission.

We have completed our review of the draft report. As part of our review, we have made several comments regarding the report. The comments can be located on pages 84, 85, and 86 of the report. If you have any questions regarding the comments, please contact Matt Sweet at (202) 219-2926.

Sincerely,

Christie McGue
Executive Director and
Chief Financial Officer

Enclosure

GAO's Comments

The following are GAO's comments on FERC's letter dated January 26, 1998.

FERC provided us with comments on how it would regulate the federal hydropower assets after a divestiture and the impact on available generating capacity as a result of relicensing nonfederal hydropower plants for which applications were filed in 1991. FERC stated that the position of its staff was that FERC did not want to license any divested federal hydropower assets on a basis that excludes some of the project's features that have a role in power production. FERC also stated that it would be able to regulate any divested assets because it had experience regulating the multipurpose aspects of over 1,600 nonfederal hydropower plants. FERC added that in its relicensing of 157 applications filed in 1991, the projects that were relicensed experienced a slight increase in total capacity available to generate power but a slight decline in actual generation. Our report was revised to address these and other suggestions.

Major Contributors to This Report

Resources, Community, and Economic Development Division

Philip Amon
Ernie Hazera
Charles Hessler
Susan Kladiva
Peg Reese
Daren Sweeney
Martha Vawter

Office of the General Counsel

Jackie Goff

Related GAO Products

Deferred Maintenance Reporting: Challenges to Implementation (GAO/AIMD-98-42, Jan. 30, 1998).

Rural Utilities Service: Opportunities to Operate Electricity and Telecommunications Loan Programs More Effectively (GAO/RCED-98-42, Jan. 21, 1998).

Federal Electricity Activities: The Federal Government's Net Cost and Potential for Future Losses (GAO/AIMD-97-110 and 110A, Sept. 19, 1997).

Deferred Maintenance: Reporting Requirements and Identified Issues (GAO/AIMD-97-103R, May 23, 1997).

Bureau of Reclamation: Reclamation Law and the Allocation of Construction Costs for Federal Water Projects (GAO/T-RCED-97-150, May 6, 1997).

Rural Development: Financial Condition of the Rural Utilities Service's Loan Portfolio (GAO/RCED-97-82, Apr. 11, 1997).

Federal Power: Issues Related to the Divestiture of Federal Hydropower Resources (GAO/RCED-97-48, Mar. 31, 1997).

Privatization: Lessons Learned by State and Local Governments (GAO/GGD-97-48, Mar. 14, 1997).

Budget Issues: Budgeting for Federal Capital (GAO/AIMD-97-5, Nov. 12, 1996).

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

Northwest Power Planning Council: Greater Public Oversight of Business Operations Would Enhance Accountability (GAO/RCED-96-226, Aug. 30, 1996).

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