

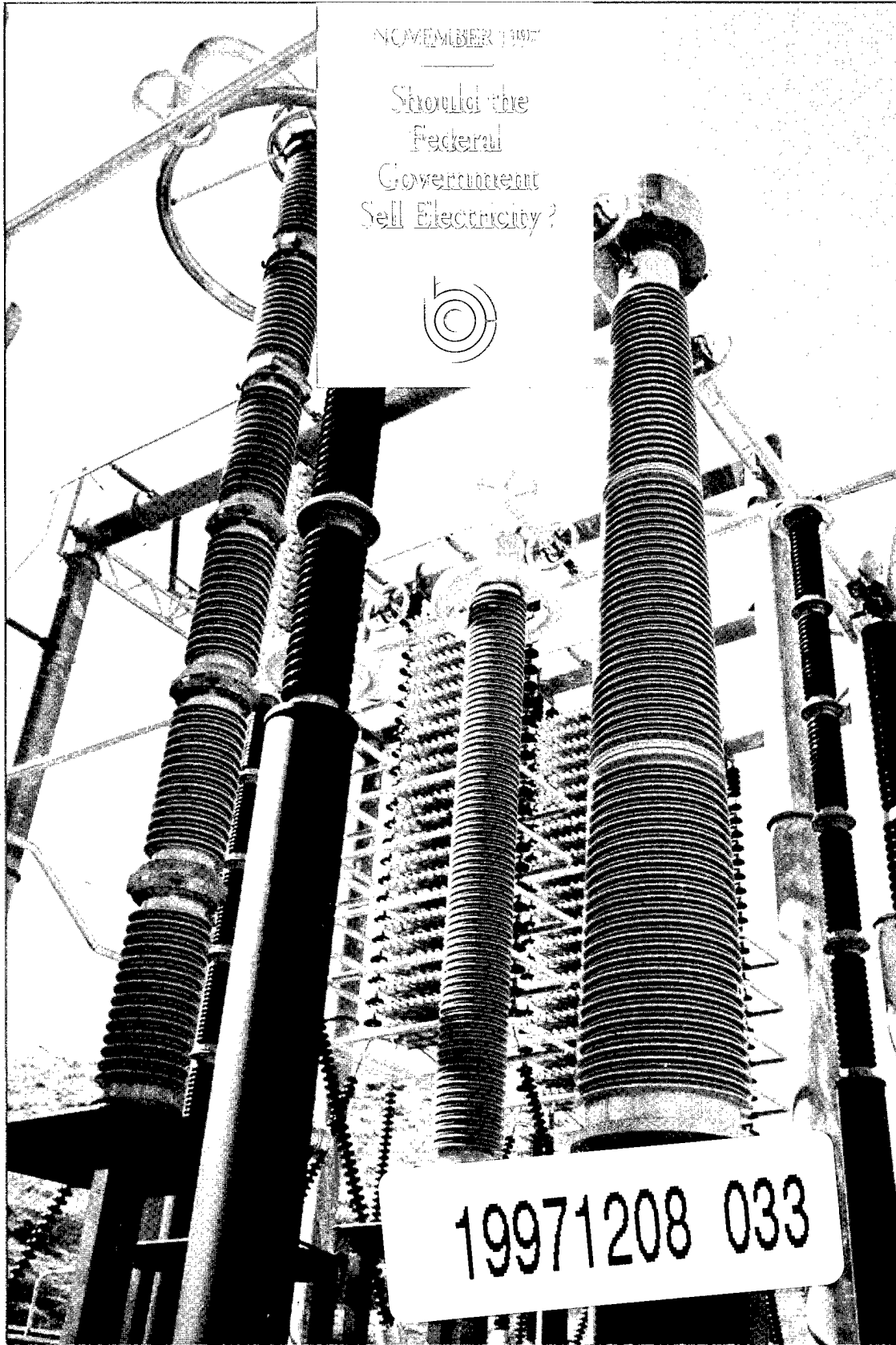
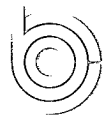
CONGRESS OF THE UNITED STATES
CONGRESSIONAL BUDGET OFFICE

CBO

STUDY

NOVEMBER 1997

Should the
Federal
Government
Sell Electricity?



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**SHOULD THE FEDERAL GOVERNMENT
SELL ELECTRICITY?**

The Congress of the United States
Congressional Budget Office

Preface

The nation originally invested in electrical power programs as a way of fostering regional development and promoting competition in power markets. Many of the projects serve multiple purposes, such as flood control and irrigation. But as concerns have risen about the efficiency of the government's power operations and the federal budget, some people question the wisdom of continuing government ownership of power assets. This study, prepared by the Congressional Budget Office (CBO) in response to a request from the House Committee on the Budget, reviews the arguments for changing the management of federal power programs and describes three options for change: management reform, transfer to local governments, and privatization. The study presents estimates of the potential market value of federal power assets and the budgetary impact of selling them.

Richard D. Farmer of CBO's Natural Resources and Commerce Division (NRCD) prepared the study under the supervision of Jan Paul Acton and Roger Hitchner. Coleman Bazelon and David Moore of NRCD provided helpful comments. Kim Cawley, Kathleen Gramp, and Jim Horney of CBO's Budget Analysis Division and Mark Booth of CBO's Tax Analysis Division contributed to the sections on budgetary background and legislative options. Robin Seiler of CBO's Special Studies Division provided an incisive internal review of the overall document. The author thanks Rodney Dunn, Daniel Feehan, Greg Kutz, and Larry Parker for their reviews of the study and many useful comments. The author also thanks the staff of the Energy Information Administration's Electric Data Systems Branch for their assistance in compiling much of the data for the study.

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June E. O'Neill
Director

November 1997

Contents

	SUMMARY	xi
ONE	THE FEDERAL ROLE IN SUPPLYING ELECTRICITY	1
	The Federal Contribution to the Nation's Power Supply	1
	Basic Power Statistics for Federal Power Agencies	3
	The Federal Investment	
	in Power Production and Marketing	8
	The Business of Federal Power:	
	Financing Construction and Paying for Operations	8
TWO	RETHINKING THE FEDERAL ROLE	13
	Public Works	14
	Economic Development	14
	Monopoly and Abuses of Market Power	14
	External Costs and Benefits of Power Generation	15
THREE	THE HIGH SOCIAL COSTS OF GOVERNMENT PRODUCTION	17
	Does Federal Management Impede Efficient Operations?	17
	Inadequate Maintenance and Its Effect	
	on Capacity Utilization	20
	New Competition Is a Mixed Blessing	
	for Federal Power Agencies	22
FOUR	OPTIONS FOR CHANGING THE FEDERAL ROLE	23
	Can Legislative Remedies Enhance Efficiency?	23
	Can Local Governments Manage Better?	26
	Can Private Businesses Manage Better?	27
	Who Benefits and Who Loses as a Result of Reform?	31

FIVE	THE VALUE OF FEDERAL POWER ASSETS TO THE PRIVATE SECTOR	35
	Which Assets Are at Stake? 35	
	What Is the Market Value of Federal Power Assets? 40	
	How Would Constraints on an Asset Sale Affect Market Value? 46	
	How to Conduct a Sale to Achieve Maximum Value 51	
SIX	BUDGETARY CONSEQUENCES OF SELLING POWER ASSETS	53
	The Budgetary Impact of Power Operations: Power Receipts and Program Outlays 55	
	The Budgetary Impact of Changing Tax Receipts 58	
	The Prospects for Long-Term Budgetary Savings 60	
	Other Considerations Enhance Prospects for Budgetary Savings 62	
	Policy Concerns Other Than the Budget 64	
APPENDIXES		
A	Federal Power Sales by State 69	
B	Cash Flows for Federal Utilities and Sensitivity Analyses of Market Values and Budgetary Effects 71	

TABLES

1.	Federal Power Sales to Utilities and Direct Customers, Fiscal Year 1995	2
2.	Sales by Federal Utilities, Fiscal Year 1995	4
3.	Generating and Transmission Capacity of Federal Utilities, Fiscal Year 1995	5
4.	Average Revenues from Power Sales by Federal Utilities and Investor-Owned Utilities, Fiscal Year 1995	6
5.	Cumulative Federal Investment in Power and Related Nonpower Assets Through Fiscal Year 1995	9
6.	Ratio of Production to Operable Generating Capacity for Federal and Nonfederal Hydropower Producers, Fiscal Years 1991-1995	21
7.	Comparison of How Fast Current Federal Rates Adjust to Market Rates for Different Reform Options and Types of Ownership After Reform	29
8.	Number of Rate-Setting Systems and Power Projects Managed by Federal Utilities, Calendar Year 1995	39
9.	Comparison of Average Revenues from Power Operations for Federal and Investor-Owned Utilities, Fiscal Year 1995	42
10.	Potential Market Valuations of Federal Power Assets	44
11.	Alternative Bases for Sales Price and Related Losses in Public Receipts Compared with Sales at High and Low Market Values	47
12.	Potential Restrictions on Plant Operations and Related Losses in Public Receipts	49
13.	Comparison of Net Budgetary Receipts, Additional Tax Receipts from the Sale of Federal Power Assets, and Market Valuations	58
14.	Comparison of Potential Budgetary Savings or Costs from the Sale of Federal Power Assets Under Varying Assumptions About Market Value	61

A-1.	Federal Power Sales to Utilities and Direct Customers, Fiscal Year 1995	70
B-1	Income and Expenditures for Power Programs of the Tennessee Valley Authority, Fiscal Year 1996	71
B-2.	Income and Expenditures for Power Marketing Administrations, Fiscal Year 1995	72
B-3.	Sensitivity of Market Valuations to Changes in Key Assumptions	74
B-4.	Sensitivity of Budgetary Effects to Changes in Key Economic Variables Affecting Repayment	75

FIGURES

1.	National Power Production by Type of Producer, Calendar Year 1995	2
2.	Federal Power Sales by Type of Customer, Fiscal Year 1995	3
3.	Service Areas of Federal Power Agencies	7
4.	Ratio of Maintenance Expenditures to Power Revenues for Federal, Publicly Owned, and Investor-Owned Utilities, Calendar Years 1986-1995	21
5.	Federal Utilities' Spending and Receipts, Fiscal Year 1995	56

BOXES

1.	The Licensing of Nonfederal Hydropower Projects	30
2.	Selling the Alaska Power Administration	36
3.	Current Budgetary Treatment of Asset Sales	54
4.	Financial Challenges to the TVA and the BPA	59

Summary

Federal agencies, including the Tennessee Valley Authority (TVA) and the five power marketing administrations (PMAs) of the Department of Energy, supply about 8 percent of the electricity consumed in the United States. Today, many policymakers question the government's involvement in the business of producing and marketing electric power. A number of proposals advocate transferring responsibility for federal power facilities to private business or local government. Others propose reforming the management of federal programs to make them operate more efficiently.

Two principal motives underlie those proposals. One is deregulation and downsizing government. Taking government out of the power business altogether would be consistent with other steps the Congress has taken toward deregulation—most recently in the Energy Policy Act of 1992—and with many people's desire to eliminate unnecessary activities of government.

The other motive is deficit reduction. The budgetary value to the government of federal facilities that generate and transmit power is substantial. But the value to the private sector might be even greater if it could raise power rates, operate facilities more efficiently, and end some subsidized sales. Opportunities exist for increasing earnings, because the goal of federal power programs has never been to maximize returns to the government. Sales of some or all of the facilities—at prices that exceeded the value to the government—would produce budgetary savings in the long run. Budgetary savings from reforming federal management, although more modest, could also help the Congress meet its goals for reducing the deficit. For

example, raising PMA power rates to average market levels could increase federal receipts by \$210 million a year.

Many proponents of eliminating or reducing federal production and sale of electric power concede that the original investment by the government was good policy. Noting that times have changed, however, they argue that most of the original reasons for federal involvement no longer apply, and that the production and sale of power should be turned over to the private sector. The economic benefits of developing the nation's water resources have been realized, and problems with poor service to rural areas are gone. Proponents of privatization also claim that the threat of monopolists manipulating the power market should no longer worry policymakers—in part because of the success of regulatory programs, in part because of new competition in those markets.

On the other side of the debate, proponents of keeping a federal role in supplying power are concerned about rate increases that some consumers might face once federal subsidies go away. They are also concerned about the management of public rivers and lakes by nonfederal entities. They feel that nonfederal operators may not have the incentives to protect the environment, manage rivers for flood control, and retain public access to recreational resources.

But even proponents of continued federal ownership acknowledge that some changes are needed in the management, financing, and pricing of public power. Budgetary restrictions on operating and investing decisions by federal managers, inefficiencies inherent in the

pricing of public power, and increasing competition from nonfederal suppliers all point to growing problems with the federal power program and the likelihood that taxpayers will bear more of the cost. Furthermore, many of the concerns about the management of the nation's water resources for environmental and recreational purposes apply equally to federal and nonfederal managers. Budgetary problems are most acute for the largest power agencies—the TVA and the Bonneville Power Administration (BPA)—but each of the smaller programs may benefit from some type of change as well.

Federal Power Agencies: Who They Are, What They Do

The federal government sells half of the power it produces through its five power marketing administrations and the other half through the Tennessee Valley Authority. The PMAs, in addition to the Bonneville Power Administration, are the Southwestern Power Administration (SWPA), the Southeastern Power Administration (SEPA), the Alaska Power Administration (APA), and the Western Area Power Administration (WAPA). Legislation authorizing the future sale of APA assets and terminating that agency became law in late 1995.

The source for most PMA sales is hydropower from dams that the Bureau of Reclamation (Reclamation) and the Army Corps of Engineers (the Corps) have built over the past 60 years and continue to operate. Power from Reclamation and Corps projects account for about one-half of the nation's total production of hydropower. Additional power that the BPA sells comes from a nuclear plant that the agency has helped finance. The Tennessee Valley Authority produces and markets the electricity it generates from coal, nuclear power, natural gas, and hydropower.

The government sells its power wholesale, principally to electric utilities and government entities. By law, the TVA and the PMAs give preference in their sales to publicly owned utilities, consumer cooperatives, and public agencies in their service regions—granting those organizations first rights to purchase federal power and supplying that power at prices de-

signed to equal, over time, the average costs of production. The TVA and the Bonneville Power Administration also sell some power directly to large businesses (mainly aluminum companies) at preferential rates. So-called nonpreference customers (mainly investor-owned utilities) may purchase federal power that the preferred customers do not need.

The influence of the federal government in supplying power is concentrated and therefore more important in certain parts of the country and in certain segments of the wholesale market than in others. For example, nearly 60 percent of federal sales go to just four states: Tennessee, Alabama, Washington, and Oregon. And more than 70 percent of federal power sales are made to publicly owned distributors and cooperatives. On average, those utilities, which directly sell 20 percent of the nation's electricity, rely on federal production for about 25 percent of their power supply.

The northeast and central regions of the country do not benefit from sales of federal power. And on net, investor-owned utilities—which sell most of the electricity in the country—receive almost no federal power.

Policy Rationale for a Federal Power Program: Then and Now

Compared with other major industries, the federal presence in what is primarily a private and local function is in many ways an anomaly, having changed little since the New Deal era of the 1930s. The direct federal role in supplying electricity emerged with the national policy to harness the nation's rivers for economic development in poor rural areas of the East and in sparsely populated or arid parts of the West. Political leadership for that policy came from the conservation movement of the late 1800s. At that time, conservation simply meant not letting water flow unused to the sea. Additional incentive for direct government intervention in electricity markets came from the populist distrust of big business at the turn of the century. Generating power was initially an incidental goal of federal projects that were intended to control floods, promote river transportation, and supply water for farms and rural communities.

Over the past 60 years, many of the concerns that gave rise to the current federal role in supplying power have greatly diminished. The disparity between the quality of life in rural and urban areas is much smaller, if not reversed. Federal and local regulation and, increasingly, competition within the industry effectively check the market power of investor-owned utilities. And the conservation philosophy of not wasting water has given way to environmental concerns about preserving the nation's waterways and protecting threatened and endangered species.

Moreover, in the intervening years, a growing recognition of the full costs of government solutions has emerged. The federal power agencies could satisfy their early social agenda, such as supporting public works and rural development, without producing electricity at minimum cost or supplying it to the consumers who would put that power to the best use. But today the social imperative for such costly practices is no longer as strong. Even if certain problems with the market remain, the high costs of government production indicate that other public solutions—such as regulation or local control—might now be preferable.

The High Costs of Relying on Government Production

The nation's hydropower resources, which enable the government to sell electricity at relatively low prices, could support more power output at today's costs (or the same power at lower cost) than is now the case. At the heart of problems with the high costs of federal production are governmental failures: behavioral impediments to socially efficient power operations. The managerial structure of the federal power program, for example, makes it hard to operate efficiently. Sources of problems include the divided responsibilities of different agencies and branches of government, the constraints of the Congressional budgeting process, and the lack of independent oversight or significant financial constraints on pricing and investing decisions. Specific evidence of the high costs of federal involvement comes from the inadequate maintenance of power assets—a problem that applies to all of the federal power agencies—and low utilization rates of hydropower-generating capacity.

Competition in power markets may contribute further to problems arising from governmental failures. In particular, adhering to the current pricing rules, which set power rates equal to average costs, and to the debt burdens of some of the federal agencies mean that those agencies will face great difficulties in meeting new competition from low-cost, independent power producers.

In general, the trend toward more open competition in electricity markets reveals the high costs of power supplied by the government. At the same time, growing competition weakens one argument for direct government ownership of production and transmission facilities: it reduces any market power that nonfederal utilities may hold. The problems of high debt burdens and competition are most pressing for the Tennessee Valley Authority and the Bonneville Power Administration.

Options for Altering the Federal Role

Diminishing benefits and rising costs of government production point to a need to reform the federal power program. Taking the government out of the power business would square with other steps the Congress has taken toward deregulating energy markets and reducing government interference in market operations. Selling the federal facilities—for the right price—could also contribute to long-term budgetary savings. But the Congressional Budget Office's (CBO's) analysis of the sources of government failures also points to changes in the management of power agencies that could help to control the costs of government production.

Three general options are available to the Congress to improve the performance of federal power agencies and enhance the efficiency of U.S. power markets:

- o *Legislative Remedies to Improve Government Management.* The Congress may retain federal ownership but legislate specific remedies to correct some of the failures arising from the management system, pricing practices, and uncompetitive market structure that characterize the federal power program. Those changes would allow federal agencies to be more efficient and compete more effec-

tively. Such improvements could increase the net returns to the Treasury from federal power operations.

- o *Transfer Ownership to Local Governments.* The Congress may decide that current market and governmental failures argue against continuing the federal role in production but, for some facilities, may call for reforms short of privatization. If that was the case, the Congress could devolve, or transfer, the ownership of federal power assets to local governments. If subject to the independent oversight of public utility commissions and the limits that borrowing or raising taxes would impose on spending, those facilities might operate more efficiently under local than federal control.
- o *Privatization.* As an alternative to devolution, the Congress could privatize federal power assets. Privatization would place control for their operation and upkeep in the hands of nongovernment entities, either by selling them or granting long-term leases for their operation and upkeep.

Among those options, privatization may offer the greatest opportunity for enhancing the efficiency of power production. Lingering governmental failures may erode any special advantages of retaining federal management, despite the government's pursuit of social objectives that private operators may not value. And local governments may fall prey to the same administrative failures that hamper federal management.

Similarly, privatization could provide the greatest budgetary savings, depending on the terms of the sale. The budget would not be significantly affected, however, if privatization meant that private contractors operated government-owned facilities but that current operating and pricing subsidies (such as pension costs for federal employees that are not in the rate base) would continue. The greatest return to the Treasury from privatization would result from a competitive sale to the highest bidder with no restrictions on who may bid, no limits on subsequent power rates, and no guarantees of continuing federal support.

The Congressional Budget Office does not attempt to predict how much power rates may change after reform or privatization of a federal program. Except for

a few states, however, the federal share of total power supply—and hence the potential for influencing average wholesale rates—is generally small. Any improved efficiency in regional markets as a result of new management or ownership would diminish cost pressures on regional wholesale rates. And with the structural changes under way in power markets, it is not clear how much of any rise in wholesale power rates could be passed on to retail customers by local power distributors.

What Are Federal Power Assets Worth to Buyers?

This study presents illustrative estimates of what federal power facilities might be worth to the private sector and the federal government. Such estimates can indicate the potential, long-term budgetary savings from privatization. But sales can vary in ways that would affect the market value of the assets. What is to be sold? When? To whom? How is the sale to be conducted? What restrictions are to be placed on operations by private owners? Because of those variables, the estimates of market value provided in this study may differ from those that buyers actually offer. Changes in the market valuations of federal power assets would alter the budgetary savings from their sale, dollar for dollar.

CBO estimated three figures for the sale of each federal power agency—the TVA and the power marketing administrations. The first figure was the maximum value to the private sector for all of the power assets of each agency. (The PMA sales included the power-related facilities of Reclamation and the Corps.) The second was the present value of additional tax receipts that the government would realize from a change of ownership. The third was the present (or capitalized) value of the net income stream to the government that would be lost if those assets were sold. The difference between the combined value to the market and additional tax receipts on the one hand, and the budgetary value to the government of continued program operation on the other, indicates the long-term budgetary savings (or cost) that would result from selling power assets to the private sector.

In addition to the uncertainties of those estimates, the government may not realize the maximum value from a sale for many reasons. The maximum value of power assets to the private sector could be established in an open competitive sale unburdened with no special conditions that might diminish future earnings or restrict who may bid. Economic theory suggests that the amount businesses would offer in such a competition would reflect their assessment of the present value of the net cash flow they would expect to earn from operating the assets in the future.

For such a valuation, CBO estimates that private businesses may be willing to pay between \$45 billion and \$62 billion for all of the power assets of the federal government. The range of market values for assets of the Tennessee Valley Authority may be \$22 billion to \$30 billion. And the Bonneville Power Administration (including the power-generating assets of Reclamation and the Corps) may be worth between \$15 billion and \$20 billion. The combined assets of the smaller PMAs—the Southwestern, the Southeastern, and the Western Area Power Administrations—may be worth between \$8 billion and \$11 billion.

Those estimates represent only the value of power-generating, transmission, and marketing assets. They do not consider the possibility of turning power assets to new and possibly more profitable endeavors that would increase their value. Similarly, the estimates do not consider the sale of nonpower assets related to the nation's multiple-purpose water projects. Offering navigation locks, recreation resources, or property surrounding a reservoir could increase the market values, too.

CBO made the following additional assumptions when preparing estimates of the maximum value of the federal power entities to the private sector:

- o The new owners would be able to raise power rates to competitive levels.
- o Private operators of hydropower facilities would generally produce electricity at a lower cost than the federal operators currently do (or, equivalently, more power at the same cost).
- o The new owners would receive no special operating restrictions or privileges. For example, they would

be subject to the same regulations that apply to other privately operated facilities. The current requirements for securing federal licensing of hydro-power projects would not impede power operations or delay the sale.

- o The debt owed directly to the public by the TVA and the BPA would remain an obligation of the federal government if those entities were sold to the private sector. Whether or not those liabilities could be passed on to a private owner, however, would have little or no net effect on estimates of budgetary savings. (The market value of federal assets would be higher if the government retained debt liabilities, but the budgetary benefits from transferring ownership would be lower.)

Critics may regard those assumptions as extreme. Some sales might be authorized under different conditions. For example, new owners might be restricted as to how rapidly they could raise rates to consumers. Environmental concerns in an area might require operational constraints to be written into the sales contract. Or the TVA and BPA public debt might be dealt with differently. Nevertheless, estimates generated on the basis of those assumptions offer a useful benchmark.

The Budgetary Value of Power Assets and the Budgetary Savings from Their Sale

Selling assets is not the same as reducing the deficit. By selling an income-producing asset, the government is trading the future income that asset will generate for a lump-sum payment today. A sale of federal power assets would yield long-term budgetary savings only if the sales proceeds plus the present value of additional tax receipts was greater than the present value of the income that the government would forgo.

This study presents estimates of the budgetary value to the government of retaining ownership, the tax effects of changing ownership, and the long-term budgetary savings or costs that would result from selling power assets to the highest bidders. Those estimates of long-term budgetary effects differ from any CBO estimates of the cost of legislation authorizing specific

sales. Legislative cost estimates, which CBO prepares for budget enforcement purposes, reflect annual cash changes in budgetary flows (that is, undiscounted) for a limited period of only five or 10 years. Such estimates would not include any future savings in discretionary spending for operations or construction. And the Joint Committee on Taxation, not CBO, would be responsible for estimating any changes in tax receipts.

The budgetary value to the government of retaining ownership is based on the difference between future revenues from power customers and the sum of the program's operating and capital costs. Under existing policies for setting power rates, current revenues pay for all costs of operation. Therefore, it is possible to estimate the net budgetary impact of power programs in terms of the amount of revenues to be collected for the repayment of past capital investments. (Those estimates exclude future expenditures for new capital projects under the assumption that those projects would also generate a balance of new revenues and repayment obligations.) The present value of capital repayment obligations for all the power agencies, discounted at the cost of federal borrowing, totals about \$46 billion. The net addition to federal tax receipts—a consequence of increased productivity—would be worth about \$0.5 billion in current dollars.

On that basis, CBO considered the potential budgetary savings from an unrestricted sale of all power assets (including the power-related assets of Reclamation and the Corps) to the highest bidder under alternative assumptions about the future course of power rates. For asset prices reflecting high market values (power rates grow with inflation after first rising to current market levels), selling all of the power programs would yield budgetary savings totaling \$16 billion. But for asset prices based on low market values (power rates remain constant after first rising to current market levels), the result could be a small budgetary cost of \$0.2 billion, not savings, because losses from a sale of TVA assets just exceed the combined savings from sales of the PMA programs.

In general, the prospects for budgetary savings from selling power assets are strongest when the new owner can boost cash flow by selling electricity at higher rates or lower costs than the government. The

prospects for budgetary savings are weakest when the government must collect large sums to repay past investments.

The budgetary savings from privatization appear greatest for the BPA, the SWPA, and the WAPA. The long-term savings from selling those three agencies would be worth between \$5 billion and \$13 billion in present-value terms. For the SEPA, the range of budgetary savings would be from almost none (that is, deficit neutral) to about \$400 million.

Selling the Tennessee Valley Authority's assets would produce budgetary savings of more than \$2 billion with a sale at the high market value—a relatively small amount compared with the overall value of the TVA program. A sale at the low market value would produce a budgetary cost amounting to about \$6 billion. In both cases, the prospects for budgetary savings from a sale are undermined by the agency's large outstanding capital debts. The range of sale prices for the TVA also reflects the limited opportunity for new owners to raise power rates in the southeast region; TVA rates are already near the market levels.

The actual budgetary savings from the sale of power assets are likely to be greater than those shown here, for several reasons. First, the estimates omit costs that are not currently part of the federal rate base. Second, they exclude the prospect of new subsidies, new capital expenditures that will not be fully repaid, and new obligations that the power agencies may incur through third-party financing. Third, the market assessments neither include the value of associated nonpower assets that could be part of the sale nor consider the prospect that new owners may find new uses for or combinations of power assets that could increase their earnings potential. The combined value of the individual pieces of the federal power program, sold separately, may be greater than the value of the program as a whole.

Conclusions

The government could save money over the long term by selling many of the facilities that it now uses to sup-

ply electric power. Under some circumstances, it could lose money. But budgetary considerations may not dominate the decision to sell power assets. The government entered the business of producing and marketing electricity for reasons other than making money, and it may decide to stay in the business for similar reasons. Many of the early rationales for direct federal involvement, however, are gone, thus weakening the arguments for continued government ownership. Nevertheless, the prospect of selling federal power assets continues to raise concerns about future electricity prices, the environment, and access to recreational resources. Some power consumers would be likely to face increases in rates under new ownership.

Estimates of the value to private businesses of taking over federal facilities and the value to the government of keeping those facilities point to circumstances that support the prospect of budgetary savings, or costs, from privatization. The estimates presented in this study are only illustrative, however. Actual sales would probably not meet the precise conditions assumed here, and an analysis of any individual sale would have to be more exhaustive than the one conducted for this study.

The Federal Role in Supplying Electricity

The federal government produces 8 percent of the electricity consumed in the United States and sells it through the Tennessee Valley Authority (TVA) and the five power marketing administrations (PMAs) of the Department of Energy. Two federal agencies—the Bureau of Reclamation (Reclamation) and the Army Corps of Engineers (the Corps)—construct and operate the facilities that produce most of the power that the PMAs sell. About 60 percent of the government-owned generating capacity—and all of the Reclamation and Corps capacity—is hydroelectric. References to PMA assets in this study generally include the associated assets of Reclamation and the Corps as well.

Many policymakers question whether the government should be in the business of producing and marketing electric power. They say that the private sector could handle those essentially commercial functions—and probably more efficiently than the government does. Selling federal power assets would cut the size of government and—if the price was right—ease the task of managing the federal budget deficit.

Not everyone agrees that selling federal power assets is a good idea. Many recipients of federally produced power get it at below-market rates and do not like the idea of losing the subsidy. Moreover, most government-owned facilities that produce power also serve other purposes: flood control, diverting and storing water for farms and cities, providing recreational opportunities, and protecting the environment. Some policymakers believe that government ownership is needed to make sure that those other functions do not suffer.

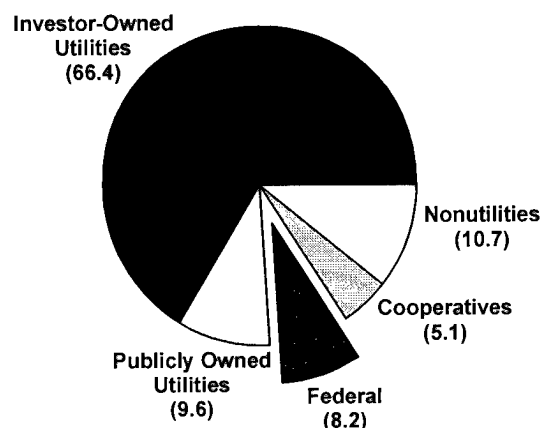
The Alaska Power Administration Asset Sales and Termination Act of 1995 authorized the sale of the Alaska Power Administration, the smallest PMA. Assets to be sold include two hydropower projects with their generating equipment, transmission lines, and administrative and maintenance facilities. Negotiations for the sale have been in progress for a decade, and the final transfer has yet to occur. Nevertheless, observers describe the Alaskan sale as "simple." The two projects being sold are in small river basins and do not involve irrigation, navigation, or significant environmental considerations.

Sales of other federal power facilities have been discussed, but none could be described as "simple." Other candidates for sale have many purposes other than generating electricity. Some of those purposes, like providing water for irrigation, might be dealt with on a private, commercial basis. Flood control and some of the recreational and environmental functions of those facilities, however, are more difficult to deal with commercially. Sales agreements might spell out how those other public purposes would be met, or existing government regulations that apply to privately owned operations might suffice.

The Federal Contribution to the Nation's Power Supply

Private businesses—including investor-owned utilities, consumer-owned cooperatives, and nonutilities—dominate the nation's electric power industry, supplying

Figure 1.
National Power Production by Type of Producer,
Calendar Year 1995 (In percent)



SOURCE: Congressional Budget Office using data on net power generation from the Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels (Forms EIA-861 and EIA-86).

NOTE: Excludes net imports, which represent less than 1 percent of the nation's total supply.

more than 80 percent of the nation's power needs (see Figure 1). (Nonutilities are independent power producers not subject to federal and local regulation of power rates or service requirements.)

Although it constitutes only a small part of the national market, the federal power supply is important in certain regions of the country—primarily the South and West—and for certain types of customers. About 87 percent of federal power is sold to utilities and industrial customers in just 10 states, with Tennessee and Washington dominating the field (see Table 1). Tennessee has few other sources, obtaining 88 percent of its needs from the Tennessee Valley Authority. (Federal laws limit the opportunities for other electric utilities to sell within the Tennessee Valley region.) More than one-half of all electricity sold in Washington is from the federal Bonneville Power Administration (BPA), the largest PMA. Many other western and southern states also obtain some part of their electricity from federal sources. Only the states of the country's northeast and central regions do not benefit from federal power programs (see Table A-1).

The preferred customers of federal agencies are publicly owned utilities (including municipalities, public utility districts, and irrigation districts) and consumer-owned cooperatives. Those distributors do not sell as much power nationwide as do investor-owned utilities, but they are more numerous and serve many of the country's small cities and rural communities. They purchase federal power for resale to homes and businesses. The preferred customers of the TVA and the BPA also include some large industrial customers—primarily aluminum producers—that buy federal power directly, without going through a local distributor. In 1995, publicly owned utilities and cooperatives accounted for more than 70 percent of total federal sales,

Table 1.
Federal Power Sales to Utilities and Direct
Customers, Fiscal Year 1995

State	Federal Sales (Millions of kilowatt- hours)	State Share of Federal Total (Percent)	Federal Share of State Total ^a (Percent)
Tennessee	74,638	30.4	88.4
Washington	46,848	19.1	52.5
Alabama	19,342	7.9	25.8
Oregon	18,759	7.6	40.6
California	15,327	6.2	6.9
Kentucky	13,531	5.5	18.2
Mississippi	11,965	4.9	29.6
Georgia	5,294	2.2	5.2
Montana	5,203	2.1	38.4
Minnesota	2,893	1.2	5.2
Other States	31,466	12.8	1.3
National Total ^b	245,266	100.0	7.6

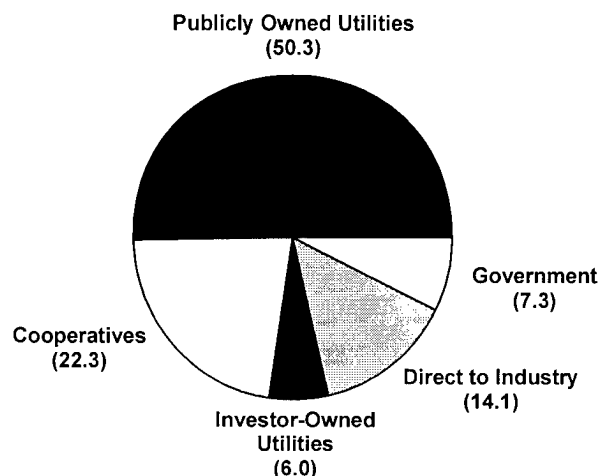
SOURCE: Congressional Budget Office using state-level data from the Energy Information Administration, based on data from Forms EIA-412 and EIA-861.

NOTE: State data include sales by federal agencies other than the Tennessee Valley Authority and the power marketing administrations. Data may exclude sales to publicly owned utilities and cooperatives in some very small communities.

a. Reflects sales to end-users by utilities and generation by non-utilities for their own use. Those data are for calendar year 1995.

b. Excludes sales and transfers to government agencies for direct consumption, totaling about 19 billion kilowatt-hours.

Figure 2.
Federal Power Sales by Type of Customer,
Fiscal Year 1995 (in percent)



SOURCE: Congressional Budget Office using data from the 1995 annual reports of the Tennessee Valley Authority and the power marketing administrations.

and direct sales to industry accounted for about 15 percent (see Figure 2).¹

The federal power agencies' preferred customers generally purchase power at wholesale rates that are lower than those paid by others across the country, in part because so much federal electricity comes from low-cost hydropower. In 1995, the average cost of federal power was 3.4 cents per kilowatt-hour (kWh) to publicly owned utilities and cooperatives and 2.7 cents per kWh to industrial customers. In that year, U.S. investor-owned utilities charged those same groups of customers 3.8 cents per kWh and 4.8 cents per kWh, respectively.

Basic Power Statistics for Federal Power Agencies

There are many similarities between the TVA and the PMAs as well as among the PMAs. They are all in the

business of supplying electrical power, and they all sell most of it to public utilities and consumer-owned cooperatives at preferential prices. There are also substantial differences, particularly in the agencies' capabilities to supply power, what they charge for it, and their nonpower responsibilities. If the government decided to sell federal power assets, those characteristics could influence the amount a new owner might be willing to pay.

The Tennessee Valley Authority and the five power marketing administrations all market federally produced power, seeking out customers and contracting to supply them. All the agencies except the Southeastern Power Administration own the transmission facilities that carry power to their customers, but only the TVA and the Alaska Power Administration directly produce the power they sell. The Bonneville Power Administration controls a small portion of the power it sells through long-term commitments with nonfederal producers, but the remaining power sold by Bonneville and the three other PMAs—the Southwestern, the Southeastern, and the Western Area Power Administrations—comes from facilities that Reclamation and the Corps have constructed and continue to operate.

The TVA stands out among the federal power agencies by virtue of its size, regional importance, and reliance on coal and nuclear power. Among the agencies, the TVA also charges the highest rates for the power it sells. Of the PMAs, the Bonneville Power Administration is notable for many of the same reasons, including its adverse experiences with nuclear power projects, internal cost pressures on its power rates, and outside competition. Indeed, in many respects, the BPA and the TVA have more in common than the BPA has with the other power marketing administrations. The remaining PMAs are by no means identical, but they share many characteristics.

Tennessee Valley Authority

The federal government created the Tennessee Valley Authority in 1933 to provide jobs, control flooding, and improve the navigability of the Tennessee River, as well as to produce electricity for the region. The agency is the nation's largest power supplier and markets about one-half of the total federal production of electricity, amounting to 134 billion kilowatt-hours in 1995 (see

1. See the 1995 annual reports of the Tennessee Valley Authority and the five PMAs (the Bonneville Power Administration, the Southwestern Power Administration, the Southeastern Power Administration, the Alaska Power Administration, and the Western Area Power Administration).

Table 2.
Sales by Federal Utilities, Fiscal Year 1995 (In millions of kilowatt-hours)

	Within Service Area					Outside Service Area	Agency Total
	Public Utilities ^a	Cooperatives	Government Agencies	Investor-Owned Utilities	Direct Customers ^b		
Tennessee Valley Authority	78,825 ^c	31,420 ^c	7,226	0	16,684	0	134,155
Power Marketing Administrations							
Bonneville	33,301	10,821	1,186	8,303	19,998	6,782	80,391
Southwestern	2,182	5,338	192	5	0	0	7,717
Southeastern ^d	1,378	3,516	1,899	35	0	0	6,828
Alaska ^e	89	77	5	244	0	0	415
Western Area	<u>13,536</u>	<u>7,851</u>	<u>8,781</u>	<u>3,864</u>	<u>0</u>	<u>0</u>	<u>34,032</u>
Total ^f	129,311	59,023	19,289	12,451	36,682	6,782	263,538

SOURCE: Congressional Budget Office using data from the 1995 annual reports of the Tennessee Valley Authority (TVA) and the power marketing administrations.

- a. Includes municipal and state utilities, and public utility and irrigation districts.
- b. Primarily sales made directly to industrial establishments.
- c. Breakdown of total sales to municipal and cooperative utilities for fiscal year 1995, as reported in TVA's annual report, based on TVA sales data for July 1994 through June 1995.
- d. Federal sales are to the Tennessee Valley Authority, which has rights to about 15 percent of the Southeastern Power Administration's capacity.
- e. Breakdown of sales is based on revenue data for the Eklutna project (all public utilities and cooperatives) and the Snettisham project (all investor-owned utilities and the state of Alaska).
- f. Excludes other sources of federal sales, which total about 1 billion kilowatt-hours. Those other sources are the Corps of Engineers, which sells power to investor-owned utilities (Saint Mary Falls, Michigan) at wholesale rates, and the Bureau of Indian Affairs, which sells power to Mission Valley Power in Montana and to San Carlos Irrigation and Colorado River Indian Irrigation in Arizona.

Table 2). Its service area covers most of Tennessee and portions of Alabama, Mississippi, Kentucky, Virginia, North Carolina, and Georgia. Most of its power is sold to publicly owned utilities and cooperatives in the TVA service area. But the agency also sold 17 billion kilowatt-hours directly to industry in 1995, primarily aluminum producers.

The TVA interprets its legislative mandate as requiring it to supply all the power its customers demand. Accordingly, it has expanded its capacity far beyond what the hydropower resources of the Tennessee River basin could provide. In addition to 31 hydroelectric dams, the TVA system today includes 12 coal-fired plants, five nuclear generating units, four natural-gas-fired plants, and 16,826 circuit-miles of transmission

capacity.² In 1995, coal-fired and nuclear plants provided over 23,500 megawatts, or about 80 percent, of the agency's developed generating capacity, and hydroelectric generators provided nearly 3,000 megawatts of capacity, or 10 percent (a megawatt is 1,000 kilowatts). Natural gas plants provided the rest (see Table 3). Part of the nuclear capacity—Watts Bar 1 and Browns Ferry 3—came on line in 1996 and will ultimately increase the TVA's net power generation by about 10 percent.

TVA wholesale rates for sales to publicly owned utilities and cooperatives (as measured by average revenues of 4.2 cents per kilowatt-hour in 1995) are the highest of all the federal utilities (see Table 4). They

2. Circuit-miles are the total length of separate electrical circuits.

Table 3.
Generating and Transmission Capacity of Federal Utilities, Fiscal Year 1995

	Generating Capacity (Megawatts)					Transmission Capacity (Circuit-miles) ^b
	Hydro ^a	Coal	Nuclear	Gas	Total	
Tennessee Valley Authority	2,987 ^c	17,522	6,016 ^d	2,510	29,035	16,826
Power Marketing Administration						
Bonneville	20,212	0	1,170	0	21,382	14,802
Southwestern	1,953	0	0	0	1,953	1,383
Southeastern	3,025	0	0	0	3,025	0
Alaska	108	0	0	0	108	90
Western Area	9,300	553 ^e	0	0	9,853	17,558
Total	37,585 ^f	18,075	7,186	2,510	65,356 ^f	50,659
Memorandum:						
All U.S. Producers	78,673	311,058	99,515	238,637	776,366 ^g	375,000 ^h

SOURCE: Congressional Budget Office using data from the 1995 annual reports of the Tennessee Valley Authority (TVA) and the power marketing administrations; the Bonneville Power Administration (available at <http://www.bpa.gov/BPA...tfact/95ff/ff.1995x.htm>); the Army Corps of Engineers; the Bureau of Reclamation; the Rural Utilities Service; and Forms EIA-412 and EIA-860 from the Energy Information Administration.

- a. Manufacturer's specified capacity for conventional hydropower (excludes pumped storage).
- b. Overhead circuit-miles of total voltages at or above 71 kilovolts, as estimated by the Energy Information Administration.
- c. Excludes capacity operated by the Corps of Engineers and marketed to the TVA by the Southeastern Power Administration.
- d. Nuclear capacity includes the Browns Ferry 3 and Watts Bar 1 units.
- e. Represents the Bureau of Reclamation's 24.3 percent share of the coal-fired Navajo Generating Station.
- f. Excludes 3 megawatts of capacity supporting direct sales by the Bureau of Indian Affairs and 20 megawatts of capacity supporting direct sales by the Army Corps of Engineers.
- g. Includes capacity fired by renewable sources other than hydropower.
- h. Excludes 31,000 pole-miles for cooperatives.

are also slightly higher than the rates that investor-owned utilities nationwide charge for sales to publicly owned utilities (3.8 cents per kWh in 1995).³ One reason for the higher rates is that the TVA generates most of its power using coal, much as investor-owned utilities do nationwide. Thus, it lacks the low-cost hydropower that supports other federal agencies. Internal pressure on TVA power rates also comes from the high costs of its nuclear projects and its large burden of debt.

Bonneville Power Administration

The Bonneville Power Administration is the second-oldest federal power agency, created by the Bonneville Project Act of 1937 to market electricity from the Columbia River basin and promote economic development in the Northwest. It is also the largest power marketing administration, selling about 80 billion kilowatt-hours of electricity in 1995, more than twice as much as the next-largest PMA and about 60 percent of the total sold by the TVA. The BPA serves Washington, Oregon, Idaho, western Montana, and small portions of adjoining states (see Figure 3). Like all the power agencies,

3. Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437(95)/1 (December 1996).

Table 4.
Average Revenues from Power Sales by Federal Utilities and Investor-Owned Utilities,
Fiscal Year 1995 (In cents per kilowatt-hour)

Sellers	Buyers Within Service Area				Buyers Outside Service Area	Agency Average ^b
	Publicly Owned Utilities and Cooperatives	Government Agencies	Investor-Owned Utilities	Industrial Customers ^a		
Federal Utilities						
Tennessee Valley Authority	4.2	2.5	*	2.8	*	3.9
Power marketing administrations						
Bonneville	2.6	2.5	3.9	2.6	1.9	2.7
Southwestern	1.3	2.0	*	*	*	1.3
Southeastern	2.8	1.0	*	*	*	2.3
Alaska	1.6	1.6	3.2 ^c	*	*	2.5
Western Area	2.0	2.6	1.6	*	*	2.1
Average for All Federal Utilities	3.4 ^d	2.4	2.9 ^e	2.7	*	3.2
Average for All Investor-Owned Utilities	3.8	*	3.6	4.8	*	*

SOURCE: Congressional Budget Office (CBO) using data from the 1995 annual reports of the Tennessee Valley Authority and the power marketing administrations. For investor-owned utilities, CBO used Energy Information Administration Form EIA-861 for calendar year 1995. Energy Information Administration data on investor-owned utility sales to other utilities are preliminary.

NOTE: * = not applicable.

- a. Industrial customers for federal agencies represent direct sales to industrial establishments. Industrial customers for investor-owned utilities represent all sales to the industrial sector.
- b. Average is calculated by dividing total revenues by total sales.
- c. Average revenues from investor-owned utilities reflect costs for the private operation of federal facilities by the principal customer.
- d. Includes sales to publicly owned utilities outside the service area.
- e. Includes sales to investor-owned utilities outside the service area.

the BPA sells most of its power to publicly owned utilities and cooperatives. But the BPA sells more power directly to industrial users, primarily aluminum producers, than any other agency. The BPA also subsidizes residential power sales by some investor-owned utilities.

Today, the BPA sells electricity from 20 hydroelectric projects run by the Corps of Engineers and five operated by the Bureau of Reclamation. It also owns and operates 14,802 circuit-miles of transmission capacity. Like the TVA, the BPA has assumed some responsibility for developing power resources throughout its service area. Consequently, it also sells electricity from a

nonfederal nuclear facility and three nonfederal hydro-power facilities that it helped finance.

Southwestern Power Administration

The Flood Control Act of 1944 authorized the creation of three power agencies to sell power from water projects run by the Corps of Engineers: the Southwestern Power Administration (SWPA) in 1945, the Southeastern Power Administration (SEPA) in 1950, and the Alaska Power Administration (APA) in 1967. In 1995, the SWPA sold about 8 billion kilowatt-hours of electricity a year, produced at 24 hydroelectric facilities run

by the Corps. The SWPA also owns and operates about 1,380 circuit-miles of transmission lines.

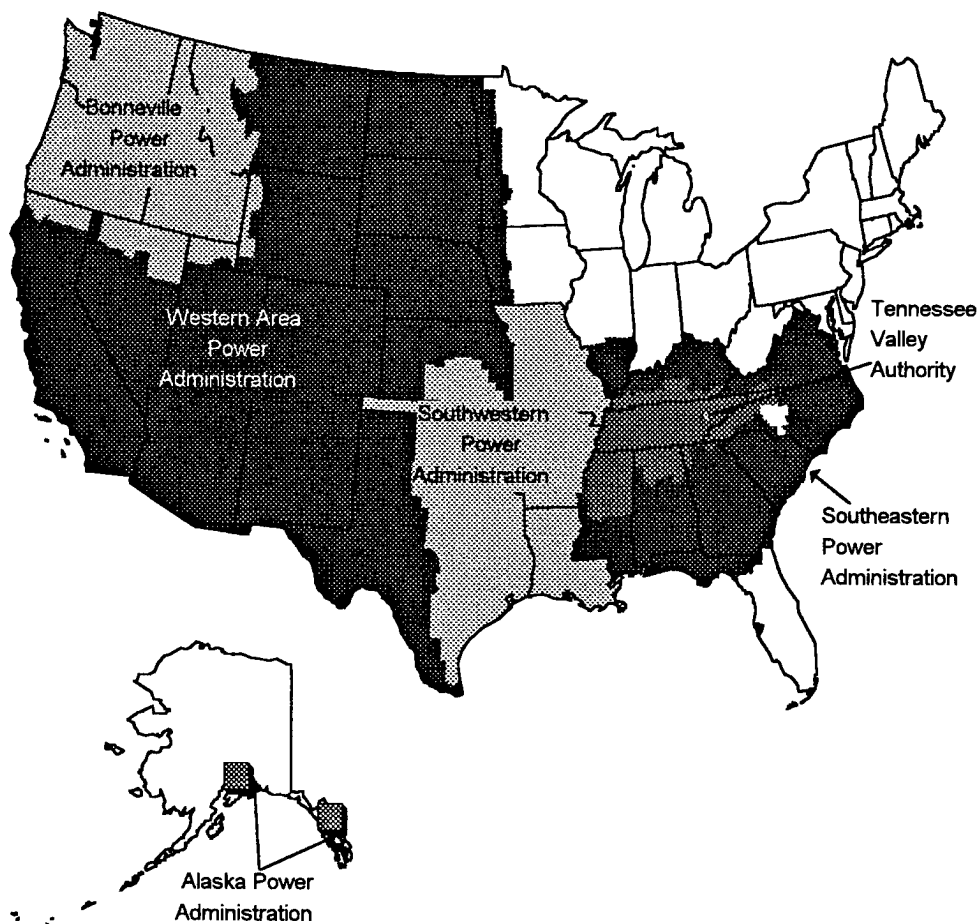
Southeastern Power Administration

In 1995, the Southeastern Power Administration sold about 7 billion kilowatt-hours of power produced at 23 Corps-run hydroelectric plants located in the southeastern part of the United States. SEPA owns no transmission lines but pays to transmit federal electricity over those of other utilities. The SEPA service area surrounds the TVA region, and more than one-fourth of the SEPA's hydroelectric power is sold to the Tennessee Valley Authority for subsequent resale.

Alaska Power Administration

The Alaska Power Administration is the smallest power agency. In 1995, it operated two hydroelectric projects, selling 0.4 billion kilowatt-hours of electricity annually. The Eklutna project serves Anchorage, and the larger Snettisham project serves Juneau. The APA also owns and operates about 90 circuit-miles of transmission capacity. Unlike the other PMAs and the TVA, the APA does not serve multiple purposes: it only generates and transmits electricity. Current law authorizes the sale of the APA.

Figure 3.
Service Areas of Federal Power Agencies



SOURCE: Energy Information Administration.

Western Area Power Administration

The Western Area Power Administration is the youngest of the power agencies, created by the Department of Energy Organization Act of 1977; but its power supplies come from some of the government's oldest and largest power projects, including Hoover Dam. Today, the WAPA sells power produced at 56 hydroelectric plants operated by the Bureau of Reclamation, the Corps of Engineers, and the International Boundary and Water Commission. It also markets power from the federal government's 24 percent share of the coal-fired Navajo Generating Station. The WAPA owns and operates about 17,560 circuit-miles of transmission lines—the most of any federal power agency—and in 1995 sold more than 34 billion kilowatt-hours of power.

The Federal Investment in Power Production and Marketing

By the end of 1995, the United States had invested more than \$62 billion in power assets (see Table 5). That figure includes the part of the total capital costs of multiple-use water projects that the government has allocated to power uses, as well as outlays for inactive nuclear projects. The government has placed about 80 percent of its total power investment in three areas: completed utility plants (generating and transmission plant and equipment), construction work in progress (including nuclear projects the TVA completed in 1996), and the Bonneville Power Administration's share of an operating, nonfederal nuclear project. The other 20 percent of the government's power investment is tied up in nuclear projects that the Tennessee Valley Authority has deferred indefinitely and in repayment liabilities that the Bonneville Power Administration has incurred for canceled nuclear investments. The share of capital costs at multiple-use water projects allocated to nonpower uses (most importantly, for navigation, irrigation, and fish and wildlife) and other BPA fish and wildlife projects adds another \$8.3 billion to the nation's investment in activities related to power production.

In general, the federal agencies must repay the public's historical investment in power assets with power revenues. Thus, historical costs should equal the sum of the outstanding debt of the agencies (for appropriations and, in the case of the TVA and BPA, borrowing from the Treasury and from the general public) and the cumulative repayment to date. For the TVA, the historical power investment is about \$34.5 billion, the face value of outstanding debt is \$27.3 billion, and cumulative repayment has been about \$7.2 billion. For the PMAs, the historical investment in power is about \$27.9 billion, the outstanding debt is \$20.9 billion, and the repayment is about \$7 billion.

The Business of Federal Power: Financing Construction and Paying for Operations

Each of the federal power agencies finances its operations and construction from some combination of power sales, appropriations, and, for the TVA and the BPA, borrowing. But the sources and control over revenues differ significantly between the Tennessee Valley Authority, an independent agency, and the power programs supporting sales by the PMAs, which rely on the budgets and activities of agencies of various Cabinet-level offices.

Independent Finances and Operations of the Tennessee Valley Authority

The Tennessee Valley Authority, as both a builder and operator of power units and a marketer of power, manages its finances and operations internally. The TVA maintains a single rate structure for its entire service area, setting rates and borrowing new funds to ensure that, over time, revenues from power sales will cover the costs of operation and maintenance, new construction, interest payments, and depreciation. (Federal agencies generally include a depreciation component in their rates as a way of paying off capital investments.)

Table 5.
Cumulative Federal Investment in Power and Related Nonpower Assets
Through Fiscal Year 1995 (In billions of dollars)

	Tennessee Valley Authority	Bonne- ville	South- western	South- eastern	Alaska	Western Area	Total
Power Assets^a							
Completed utility plant							
Generating	13.8	5.9	0.9	1.5	0.2	2.8	25.1
Transmission	2.7	4.4	0.1	0	b	2.1	9.3
Other	1.9	0	0	0	0	0.1	2.1
Nonfederal power projects	0	2.8	0	0	0	0.2	3.0
Construction in progress	8.6	0.4	b	0.5	0	0.4	9.9
Inactive nuclear projects ^c	6.2	4.4 ^d	0	0	0	0	10.6
Energy conservation projects	0	0.7	0	0	0	0	0.7
Inventories	1.3	0.1	b	0	0	0.1	1.5
Subtotal	34.5	18.7	1.1	2.0	0.2	5.6	62.2
Subtotal Excluding Inactive Nuclear Projects	28.3	14.4	1.1	2.0	0.2	5.6	51.6
Nonpower Assets (At multiple-use projects) ^e	0.9	3.2	1.7	0.9	0	1.5	8.3
Total	35.4	22.0	2.8	2.9	0.2	7.2	70.4

SOURCE: Congressional Budget Office using data from the 1995 annual reports of the Tennessee Valley Authority (TVA) and the power marketing administrations.

NOTE: Data exclude current assets (other than inventories) and nuclear decommissioning funds.

a. Includes property, plant, and equipment. Excludes cash assets, accounts receivable, capital lease assets, and deferred charges.

b. Less than \$50 million.

c. Includes deferred TVA projects (units at Watts Bar 2 and Bellefonte 1 and 2, for which no completion plans exist) and canceled Bonneville Power Administration (BPA) projects (investments of the Washington Public Power Supply System for which the BPA has incurred debt repayment obligations).

d. Minus accumulated amortization.

e. Includes irrigation, navigation, flood control, fish and wildlife conservation, and recreation.

The agency's annual statement of revenues and expenditures, reflecting those specific costs, indicates a positive net income in 1995 of \$10 million.⁴ The agency has significant discretion in setting its rates, however,

and therefore can exclude from its rate base the depreciation and construction costs for work in progress or interest costs on debt to finance that work. TVA power rates are not subject to review by any independent authority.

Since 1959, the TVA has had to meet all its power expenses from power revenues and public borrowing.

4. See the 1995 annual report of the Tennessee Valley Authority.

In 1995, the agency financed its activities with \$5.4 billion in revenues from power sales and \$1.1 billion in proceeds from borrowing. Public borrowing is primarily long-term debt in the form of TVA bond issues. In 1979, the Congress raised the cap on the agency's public borrowing to \$30 billion, of which the TVA had used about \$26.7 billion by the end of fiscal year 1995.⁵

Although the agency no longer receives Congressional appropriations to pay for operations and construction related to its power programs, it originally built up a part of its operations with Congressional appropriations and Treasury financing. At the end of fiscal year 1995, the TVA still owed the rest of the federal government \$4 billion—\$0.6 billion for past appropriations (or appropriated debt) and \$3.4 billion in debt held by the Federal Financing Bank of the Department of the Treasury.⁶ (Appropriated debt does not count against the agency's \$30 billion debt limit.)

Power Marketing Administrations' Dependence on Congressional Appropriations and Lending

The budgetary and managerial relationships between each of the power marketing administrations, which sell federal power, and Reclamation and the Corps, which produce it, are complex. It is useful to distinguish the budgetary treatment of smaller PMAs from that of the Bonneville Power Administration and the Western Area Power Administration.

Separate Budgeting for Marketers and Producers. In general, the PMAs return all revenues from power sales directly to the Treasury. Independent of those revenues, Reclamation, the Corps, and the PMAs each receive annual appropriations from the Congress to pay for their operation and maintenance activities and some new construction. The PMAs are responsible for repaying all those appropriations with interest by establishing power rates that cover costs for capital deprecia-

tion (for construction appropriations), operating expenses (for all other appropriations), and any interest payments that legislation may have required. Each PMA coordinates its operations and finances with Reclamation and the Corps through one or more regional power systems.

Like the TVA, the PMAs have some discretion over power rates; they may exclude from their rate bases the construction and borrowing costs associated with incomplete projects. Unlike the TVA, however, PMA power rates undergo some independent review. The Federal Energy Regulatory Commission (FERC) approves rate schedules that the PMAs establish for their long-term sales contracts (greater than one year). Under provisions of the Pacific Northwest Electric Power Planning and Conservation Act of 1980, the FERC also decides whether to accept on an interim basis the long-term rates that the BPA wants to introduce. The other four PMAs rely on the Department of Energy (DOE) to approve their long-term rates on an interim basis.⁷

Outside review of PMA rates, however, is mainly procedural. The FERC and DOE make sure that the PMAs relate their rates to costs in a businesslike manner, but they may not challenge the basic cost estimates that the PMAs use.

The Bonneville Power Administration: Self-Financing Transmission and Marketing. The BPA and, to a lesser extent, the WAPA are exceptions to the general budgetary and appropriation process. Reclamation and the Corps continue to rely on appropriations to support the power marketers, both to operate and maintain old power-generating facilities and to construct new ones. But like the TVA, the Bonneville Power Administration no longer receives direct funding from the Congress for its transmission and marketing activities. And the BPA no longer returns any of its sales proceeds to the Treasury, except for direct payments of principal and interest on past appropriated debt.

The Federal Columbia River Transmission System Act of 1974 authorizes the BPA to use revenues from power sales in lieu of appropriations for transmission expenses. The act also authorizes the BPA to issue

5. Ibid. For a recent analysis of the agency's finances, see General Accounting Office, *Tennessee Valley Authority: Financial Problems Raise Questions About Long-Term Viability*, GAO/AIMD/RCED-95-134 (August 17, 1995).

6. See the 1995 annual report of the Tennessee Valley Authority.

7. Department of Energy, Delegation Order No. 0204-108, effective August 23, 1991, *Federal Register*, vol. 56, p. 41835.

revenue bonds to (that is, borrow from) the Treasury up to a limit to finance construction of new transmission facilities. Today, the cap on that borrowing authority with the Federal Financing Bank is \$3.75 billion—\$2.5 billion for transmission projects and \$1.25 billion for conservation and renewable energy projects. At the end of fiscal year 1995, the BPA had used about \$2.6 billion of that line of credit.⁸

The Bonneville Power Administration can also borrow in private capital markets. By committing itself to purchase the output of certain nonfederal projects, the BPA has become a party to loans (or bonds) that finance nonfederal construction. The Pacific Northwest Electric Power Planning and Conservation Act of 1980 authorized the BPA's use of such third-party financing for construction projects by both public and investor-owned utilities. BPA-financed programs have included nuclear generators, steam plants, and energy conservation projects.

In a more recent step toward making the power-generating activities of the BPA self-financing, the Energy Policy Act of 1992 gave the BPA authority to transfer some power revenues directly to the Corps of Engineers. The act authorizes the Corps to spend those funds at the BPA's direction without any restrictions from subsequent appropriations to the Corps.

The Western Area Power Administration: Financing Some of Its Own Generating Projects. The Western Area Power Administration also has discretion

over a part of its power revenues. The WAPA has authority from the Hoover Power Plant Act of 1984 to spend the proceeds of sales from the Boulder Canyon project (Hoover Dam) without needing new appropriations. The project's proceeds are deposited in the Colorado River Dam Fund—an account of the Bureau of Reclamation. Those funds are available to Reclamation to help pay for operation and maintenance and for interest costs. Several smaller projects also have revolving funds that allow them to spend power revenues directly on operation and maintenance expenses without the need for annual appropriations. Those projects are Colorado River Storage, Colorado River Basin, Fort Peck, Seedskaadee, and Dolores.⁹

The WAPA does not have the same authority as the TVA or the BPA to borrow by issuing bonds to the Treasury or the general public. Under the authority of the Hoover Power Plant Act, however, it has solicited nonfederal financing of capital improvements to the Hoover Dam's generating facilities. The agency is repaying those investments plus interest by way of credits on the subsequent sale of power. The state of Wyoming has financed improvements at the Buffalo Bill Dam under a similar arrangement. The WAPA is currently studying customer financing of capital improvements for Shasta Dam.

8. See the 1995 annual report of the Bonneville Power Administration.

9. *Budget of the United States Government, Fiscal Year 1998: Appendix.*

Rethinking the Federal Role

The federal presence in the production and marketing of electricity, which is primarily a private and local function, is in many ways an anomaly, unchanged since the New Deal era of the 1930s. That presence is the result of a political and regional debate about appropriate roles for the public and private sectors in managing the nation's water resources in general and the supply of electricity in particular.

Most of the reasons that direct federal development and ownership of facilities that produce electricity might have been appropriate in the 1930s are no longer valid. Some original purposes have been accomplished. Some can now be accomplished through federal regulation rather than ownership. Others have diminished in importance because of greater competition, especially in wholesale power markets. But several new rationales for involving the government have arisen, too—particularly those concerning the environmental services and activities of the power marketing administrations and associated facilities. Many people argue, however, that those environmental goals can be achieved without government ownership of the commercial aspects of the federal power system.

Providing jobs and improving economic conditions in arid and rural areas of the country were the main reasons for federal investment in water projects and their power-generating facilities. Jobs were created during construction, an important factor during the high unemployment period of the 1930s. The irrigation, flood control, and navigation services of the facilities stimulated the economies of the areas served. The generation of electricity was sometimes secondary to those other

outcomes, but it was not incidental. The ability to sell power helped justify many projects. Moreover, electrification of rural areas was national policy at the time. Federal power helped achieve that goal.

When many of the federal power facilities were being built, private suppliers of power were viewed with great suspicion. As far back as the development of power facilities at the Muscle Shoals site on the Tennessee River in the 1920s, policymakers worried that the first firms to develop hydropower sites would acquire an unfair cost advantage over future potential suppliers in the region. That advantage could allow them to restrict supply and raise prices.¹

Furthermore, a popular view at the time held that private electric power companies were using their market power and were withholding supplies to rural communities. True or not, those concerns led to major federal involvement in the market for electricity and substantial federal investment in the electrification of rural areas. Keeping the production and sales of power at federal dams in government hands was a natural consequence.

All of the original rationales have been used to justify federal development and, in some cases, continued ownership of federal power facilities. But most of them are now far less compelling than they may have been at one time.

1. For a summary of the early policy debate and references to other historical accounts, see David L. Shapiro, *Generating Failure* (Washington, D.C.: Cato Institute, 1989).

Public Works

Many of the facilities that produce power sold by the PMAs started in the 1930s as public works projects with the near-term goal of producing jobs at a time of high unemployment. The construction of the dams, locks, canals, and generating facilities of the government projects employed thousands of people. Certainly, unemployment declined in areas where the construction was taking place. Unemployment for the nation as a whole may also have declined and total income may also have risen as a result of the government spending, although that type of success for public works projects is less certain.

Public works had to begin as government projects. But whatever stimulus those projects provided to national or regional economies was realized long ago and no longer justifies government ownership.

Economic Development

The major projects of the Depression were not only public works but also investments made to provide long-term economic benefits to arid and rural areas. They created an engine for regional economic development by promoting agriculture, navigation, flood control, and electrification. Such government investment might have been wise even if the public works motive had been absent.

As long as a development project increases net investment in a region, it will benefit the local economy regardless of whether government or business does the investing. For many of the early water projects, however, the government was the only possible builder. The scale of the projects, the risks, the use of publicly owned lands and eminent domain, and the public benefits for which no commercial markets existed all made it impossible for private investors to do what the federal government did.

Most analysts believe that those investments in economic development were successful. Economic conditions improved in most of the areas served—industry

was attracted, jobs were created, irrigated agriculture flourished, and lives were improved.

The flow of services from those projects—power, water for municipal areas and irrigation, flood control, and recreational amenities—contribute to economic conditions in the area. The services matter, not the identity of the owner. If the services remained the same, the power facilities could be sold with little effect on local economies.

Supporters of continued government ownership are concerned, however, that the flow of services might not be maintained, particularly the preferential power rates and access to recreational amenities. Proponents of selling PMAs and their facilities either have to find ways to ensure that the services will continue or must convince the Congress that the benefits of selling exceed the costs of losing some of those benefits.

Monopoly and Abuses of Market Power

Having more than one firm operating in some parts of the market for electricity may not be practical. In retail distribution, for example, the high costs of stringing wires to each residence mean that it is probably most efficient for one firm to serve any given area. Or the costs of regionwide power-grid failures resulting from local imbalances of power production and demand may argue for unified ownership of generating and transmission activities. Although economies of scale may support the existence of only one or a few firms, such "natural monopolies" pose the risk that without government intervention, their owners could exploit customers.²

In the 1930s, the potential for a natural monopoly existed in both the distribution and generation of power, particularly for hydropower. Any firm that could build a hydroelectric facility, which costs a lot to construct but little to operate, could dominate the market in the area. The local market might be too small to

2. For a discussion of natural monopoly in various stages of the electric power industry, see Paul L. Joskow and Richard Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation* (Cambridge: MIT Press, 1983).

attract a competitor, especially given the high costs of entering the business.

Regardless of the source of uncompetitive behavior, many people were seriously concerned during the 1930s that allowing a private business to generate, distribute, and sell all the electricity in a region would not serve the interests of the public: monopolists could charge customers more than a socially efficient price for power. Electricity might be underused, economic benefits might be limited, and abnormal profits could flow to the monopolist.

Government responded to those fears by extensively regulating private business and directly owning and providing services. The government used the following four basic types of intervention:

- o Through the Tennessee Valley Authority and the power marketing administrations, the federal government entered directly into competition with private suppliers in some markets.
- o The federal government strengthened the ability of local distribution companies to compete with private wholesalers. It did that by providing financial support for cooperatives and tax exemptions for publicly owned utilities and cooperatives.
- o The Federal Power Act of 1935 established a regulatory framework for federal and state control of prices and services. (The act was the first attempt to bring the interstate features of the electric power industry under federal regulation by empowering the Federal Energy Regulatory Commission—formerly the Federal Power Commission—to regulate the transmission of electricity in interstate commerce and the wholesale marketing of electricity by businesses active in interstate commerce.) The new availability of federal power supplies also supported local regulators and distribution companies by providing a yardstick by which they could judge the reasonableness of private power rates.
- o The newly created Securities and Exchange Commission (SEC) was charged with overseeing and limiting the ability of private companies to extend market power through holding companies. Specifically, the Public Utility Holding Company Act of 1935 authorized the SEC to approve acquisitions

and divestitures by investor-owned utilities that the government designated as public utility holding companies. (Holding companies are corporations formed for the main purpose of owning and supervising the management of subsidiary corporations through the ownership of stock in those subsidiaries.) The SEC currently registers 12 electricity holding companies for regulation under the act; those 12 companies together control 85 subsidiary utilities and 118 other companies responsible for generating about 20 percent of the nation's power.³

Many of the original fears of market abuses by private suppliers of electric power have been alleviated by the successes of government regulation and the rise of competition. The trend in regulation is to encourage competition rather than constrain private behavior. Although federal ownership still helps avoid problems with uncompetitive markets, it is not needed for that purpose. Federal ownership as a means of controlling markets is redundant, since many federal and state regulations already prescribe power rates and service requirements. And those regulations are themselves becoming redundant, since competition is imposing constraints on market performance.

External Costs and Benefits of Power Generation

The act of producing one commodity can affect the costs or benefits associated with other activities. In general, if no market exists for those external costs and benefits, a private producer tends to overlook them. Incomplete price signals might lead a producer to invest the wrong amount in a facility and, from the perspective of the entire economy, to operate it inefficiently.

Hydroelectric facilities are classic illustrations of the existence of such external effects, or externalities.⁴ A hydroelectric dam might reduce downstream flooding of agricultural land—a positive externality, or benefit,

3. Securities and Exchange Commission, *Financial and Corporate Report: Holding Companies Registered Under the Public Utility Holding Company Act of 1935* (November 1, 1994).

4. See U.S. Geological Survey, *Dams and Rivers: Primer on the Downstream Effects of Dams*, USGS Circular 1126 (June 1996).

for which the owner of the dam is not compensated by the farmer who benefits. The dam might also ruin a fishery—a negative externality, or cost, if the owner of the dam does not have to pay the sport and commercial fishers who lose. Those examples are not contrived. Most hydroelectric facilities are part of complex water projects that can significantly affect the economy and ecology of their area in ways that are not represented well, or at all, in the market.

Government intervention is often justified by such nonmarket, external effects. Government can make investment and operating decisions based on factors other than market returns. Private businesses can, too. But private businesses that make investment decisions that have a large social but no private payoff cannot survive in a competitive market.

Some of the strongest arguments for continued federal ownership of power facilities are based on the external effects of power-generating activities. Some externalities, such as the effect of dam operations on flood control and access to recreational areas, have been part of the equation since those facilities were built. The economic benefits of flood control and recreation have increased over time along with downstream economic development and population growth.

Other externalities were not envisioned by the original planners of the federal power program. They are mainly the effects of reservoir operations on the habitats of threatened, endangered, or commercially important species. The construction and past operations of existing projects have caused extensive environmental damage. But those environmental externalities are new only in the sense that they now weigh more heavily in decisions about construction or operation than they did decades ago.

Some projects almost certainly could not be justified in today's climate. The Animas-La Plata project, one of the last major development efforts of the Bureau of Reclamation, has been held up for years because of concerns about environmental effects as well as the project's impact on such cultural resources as historical sites and natural phenomena.

Environmental concerns have led to changes in the design and operation of some facilities. The construction of fish ladders and screens and efforts to limit rapid changes in river levels, for example, are intended to make river systems more "fish friendly." Even with the changes made to date, the water requirements of power generators continue to compete with those of fish and wildlife. That competition clouds the prospects for further changes in the management of hydropower facilities. The conflicting requirements of different species make it difficult to agree on the changes needed, too. For example, the type of river management that benefits migrating fish may not result in optimal water conditions for lake fish. Important dimensions of the problem to be traded off include river flows, water levels in lakes, water temperatures, nitrogen and salt concentrations of water, and physical barriers to fish migration.

The costs of the trade-off between power and the environment are real. For example, the Bonneville Power Administration claims it lost \$33 million in revenues during 1994 because it had to increase water flows for fish runs. And in the same year, the Western Area Power Administration's bypass releases of water to raise river temperatures cost the WAPA \$5 million in additional expenditures to buy power from third parties.⁵

Private owners may not weigh the environmental costs in the same way as the government does in making investment and operating decisions. Some environmentalists argue that federal ownership is necessary for just that reason. But nonfederal operators are limited by regulations and licensing procedures. Future private owners of PMAs and their facilities would be required to adhere to the same regulations or could be further constrained by provisions in the sales agreement.

The uncertainty surrounding the environmental effects and what to do about them makes it hard to specify fully what would be expected of private owners. Such uncertainty limits the value of the facilities to private buyers.

5. See the 1994 annual reports of the Bonneville Power Administration and the Western Area Power Administration.

The High Social Costs of Government Production

P olicymakers considering the future of federal power assets must examine the costs as well as the benefits of federal ownership. An important component of cost is how efficiently the government generates and markets power. Could the private sector supply power more efficiently? An affirmative answer has two implications, both favorable. First, a transfer to the private sector would improve the overall performance of the economy. Second, the greater the potential gain in efficiency from a transfer to the private sector, the greater would be the price that private interests would be willing to pay for the facilities and the more likely that such a sale would generate long-term budgetary savings for the government.

In principle, government could operate as efficiently as the private sector. The power agencies are already supposed to operate in a businesslike manner, and new management reforms, such as creating "performance-based organizations," will help to move further in that direction. But government probably does not operate the commercial aspects of the production and marketing of power as efficiently as the private sector—perhaps, as economists believe, because private and government managers face different objectives and incentives. Although evidence to support that theory is difficult to come by, there is some indication that federal power operations might run better by transferring ownership to the private sector.

Market protection and lack of competition can allow inefficient management to survive in either the pub-

lic or the private sector. But electricity markets are becoming more competitive, largely because of regulatory reform. That competition is already prompting managers of some federal power programs to look for cost savings and change the ways in which they set rates. Any failure to keep pace with growing competition may necessitate increasing taxpayers' support for federal power.

Does Federal Management Impede Efficient Operations?

The organization and financing of federal power operations can make it hard for government managers to function efficiently, even when they are motivated to do so. The first of three impediments to efficient operations involves the division of responsibilities among agencies and the Congress and the role that the budget and appropriation process plays in that division. The second stems from the availability of low-cost federal financing, unrestrained by independent assessments of economic merit. And the third is the lack of independent oversight of pricing and investment decisions by the power marketing administrations and the Tennessee Valley Authority. The division of responsibilities diminishes the government's incentives to minimize costs; the other impediments remove potential checks on poor decisionmaking.

Divided Responsibilities and the Budget Process

Efficient, businesslike management requires good flows of information, proper incentives, and accountability. Responsibilities within the government are divided among groups with varying interests, however, and information does not flow smoothly. Such conditions can lead to inefficiency—and probably do.

The problems arising from divided responsibilities are probably most acute for the power marketing administrations. Those problems stem from two sources: interagency coordination and the flow of money (and the information it conveys). First, the need to coordinate efforts is essential because one agency (the PMA) sells the power and another (the Bureau of Reclamation or the Army Corps of Engineers) produces it. Although the agencies try to coordinate their efforts, they also have interests and agendas that may conflict. Sales and production are also often handled by different departments or divisions in the private sector, and coordination can be a problem. But the profit motive helps keep private managers focused on the principal objective. Under government ownership, the PMAs lack that incentive.

The second source of management problems is the flow of money. In the private sector, prices and receipts carry much useful information that aids management decisions: Should output be raised or lowered? Should prices change? Should new capacity be built or maintenance increased? In private business, money talks. In the public sector, however, information provided by the flow of money is muted. In general, receipts from power sales go directly to the Treasury, not to the operating agencies. Thus, a drop in current or expected receipts, for example, would not signal the need for those agencies to scale back on spending; nor would an increase provide the direct wherewithal to raise spending. Instead, expenditures by the Bureau of Reclamation and the Army Corps of Engineers on the power-generating facilities depend on appropriations. When the Administration requests appropriations and the Congress grants them, the power receipts certainly influence the amount of money that goes to each agency and activity. But appropriations are often constrained by the need to keep federal spending down, and they compete with other spending needs within each appropriation bill or agency.

Even if managers of power agencies had the proper incentives to increase production, the process of budgeting and setting appropriations would make it difficult to plan such an increase in a least-cost manner. In deciding how to raise production, the federal manager is not free to make a least-cost choice between additional expenditures on operation and maintenance and additional expenditures on capital equipment. New, highly visible construction projects are often easier to fund than is additional maintenance for existing projects. And once the agencies obligate appropriated funds for multiyear capital projects, spending commonly continues until completion, even if the economic prospects for the project change. Funds for operation and maintenance are obligated for shorter periods, often less than a year, and are more exposed to changes in the budget priorities of parent agencies and the Congress.

The TVA avoids some of those problems because it combines under one management the functions of generating and marketing power. Furthermore, under the Tennessee Valley Authority Act Amendments of 1959, the TVA has direct control over its expenditures and rate setting and has the authority to reinvest excess earnings in its power program. Its decisionmaking, however, shares other problems with the PMAs.

Easing Financial Restraints on Decisionmaking

In the private sector, businesses face limits on their ability to make and repeat unprofitable operating and investment decisions. If they do not operate at the lowest cost possible, a competitor with a higher profit margin can expand production and take away customers. If businesses try to borrow money to finance capital projects, repay outstanding debt, or cover operating losses, financial markets insist on security for the loan—often in the form of evidence of future earnings or other marketable assets. Generally, businesses require new investments to demonstrate an earnings potential that is at least as high as the cost of borrowing or the return they could earn from spending those funds elsewhere.

The federal power agencies are not subject to those constraints. The agencies may benefit from subsidies for construction costs—that is, from allocating less than the correct share of the total costs of certain multipurpose projects to power users. They may also benefit

from the ability to exclude certain capital expenses (such as work in progress) or operating expenses (such as benefits for PMA employees) from their rates.¹

Furthermore, financing requirements do not impose the same discipline on federal spending that they do on private businesses. Federal agencies' cost of external borrowing is generally below the cost of money to private borrowers, and for the agencies with some discretion over their spending, the cost of internal funds is effectively zero. As a result, some otherwise unprofitable ventures appear economic, and the government (and society) spends some funds on power that it could better use to address other problems.

Congressional appropriations are the main source of financing for the power marketing administrations, Reclamation, and the Corps. In general, the Congress establishes the interest charge, if any, that the PMAs should recover in repaying appropriations for power-related construction. Those mandated charges are commonly far below market rates. The Bonneville Power Administration has access to additional funds from the Federal Financing Bank at the government's low cost of borrowing for financing investments in transmission facilities and certain environmental programs. The Tennessee Valley Authority is also repaying some debt to the bank and a small amount of appropriated indebtedness, but the public bonds that the agency issues are its main external source of financing. The TVA is able to borrow from the public at low rates, too, reflecting the implicit backing of the federal government rather than the viability of the project.² (The federal government protects the TVA from outside competition, allows the agency to set its own power rates and secure them by requiring that customers provide 10 years' advance notice before leaving the TVA system, and assures private lenders that they will be repaid first.)

Subsidies for financing stem from several sources. They are the result not only of low rates of interest but of generous repayment schedules (based on estimated

service lives of up to 90 years), the ability to defer scheduled payments, and the practice of allowing power agencies to repay their highest-cost loans first (regardless of maturity).

Some agencies have access to internal funds—the revenues they earn by generating and distributing power—which they may spend without the need for Congressional appropriations. The possibility that the agencies may earn a greater return from spending that money on nonpower programs, however, does not restrict their investments in power, since they cannot spend those internal funds elsewhere. The TVA, for example, must pump all its revenues back into the power program or use them to repay debt. The same is true for BPA spending on its transmission program. The remaining PMAs have relatively little spending discretion; except for revolving funds on some projects, all power revenues go to the Treasury.

All of the power agencies, however, have demonstrated some ability to avoid the limits that Congressional appropriations or borrowing limits would otherwise impose. For example, by means of such accounting devices as net billing and net power exchanges, an agency can enter into a long-term arrangement with a nonfederal entity that will supply power or build, maintain, or operate facilities to supply power for federal sale. The agency can "pay" for those services by purchasing the nonfederal power or by selling federal power at a discount to the nonfederal entity.

The cost to the federal government of that type of third-party financing is the difference between what the agency gets and what it gives up. The BPA originally obligated the federal government to finance investments by the Washington Public Power Supply System by guaranteeing to purchase its power. The Alaska Power Administration pays a private utility to operate its Snettisham project with discounted power. The Congress authorized the Western Area Power Administration to obtain customer financing for upgrades at the Hoover Dam, and that agency is now investigating similar arrangements to pay for upgrades at other sites. And the TVA recently contracted to purchase power on a long-term basis from a newly constructed brown-coal plant in Mississippi.

1. General Accounting Office, *Power Marketing Administrations—Cost Recovery, Financing, and Comparison to Nonfederal Utilities*, GAO/AIMD-96-145 (September 1996).

2. See, for example, Standard & Poor's, "Tennessee Valley Authority Bonds Rated AAA," *Creditweek Municipal*, May 22, 1995.

No Independent Oversight of Federal Power Rates

For electric utilities, federal and state regulations and oversight by public utility commissions (including the Federal Energy Regulatory Commission) have long taken the place of the discipline of the market. And in recent years, competition in wholesale markets has begun to provide a check on the unprofitable activities of those utilities. By contrast, the federal power agencies have not been subject to the regulatory oversight imposed on public and private electric utilities and remain largely isolated from the rigor of market pricing and financing.

On paper, the FERC is responsible for approving electricity rates that are set by the power marketing administrations. In practice, the PMAs set their own rates for long-term contracts, subject only to review by the FERC for final rates or by the Department of Energy for interim rates. (Long-term contracts establish rates for more than one year.) That review is limited to assuring that PMA rates reflect reported costs. The FERC and the Department of Energy do not have authority to challenge the basic cost estimates underlying the PMAs' rate calculations. Moreover, the PMAs are completely free to set rates for short-term contracts (generally for sales of interruptible power to nonpreferred customers), subject only to political and competitive pressures and the requirement that changes in revenues from nonpreferred customers be reflected in the rates for preferred customers, which the FERC does review. No federal or state agency has even taken oversight for any TVA rates.

The lack of substantive oversight was by design. The Congress did not want to invest the FERC with that task because of the agency's separate responsibility for approving rates for privately owned utilities operating in interstate commerce.³ To some Members, a regulatory responsibility that would include public and private suppliers who were potential competitors represented an opportunity for conflict of interest. If the FERC set public power rates too high, that would benefit private companies, and vice versa.

Today, such concern about capricious pricing rules at the FERC is unwarranted. The rules directing the composition of interstate wholesale rates are well established in federal regulations. Arbitrary pricing policies are more of a problem for the federal power agencies than for private utilities. One of the arguments made in favor of a federal power program in the 1930s was the need to have public prices as a yardstick against which to measure the reasonableness of private power rates. In the 1990s, that argument has turned around: private rates now serve as a yardstick to gauge federal performance and help guide the federal program regarding trends in demand.

As competition in wholesale power markets grows, the protections enjoyed by federal producers will diminish. Competition will impose increasingly stringent constraints on federal pricing and investment decisions, which will heighten the need for changes in federal management.

Inadequate Maintenance and Its Effect on Capacity Utilization

The inadequate maintenance of power assets and the resulting low use of power-generating capacity show how high the costs of supplying federal power are. The government could reduce its production costs by performing more maintenance, perhaps by diverting some funds from new construction.

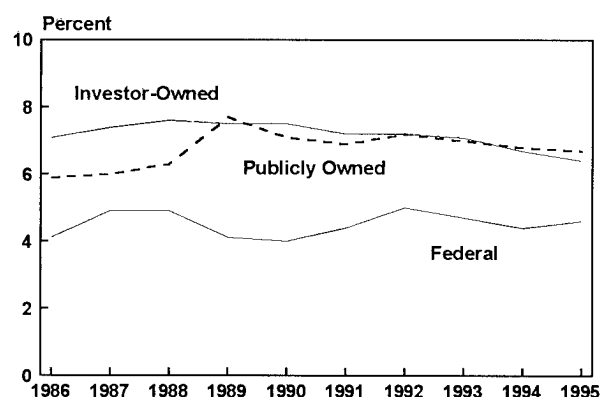
The federal government spends significantly less than investor-owned utilities and other publicly owned power systems on maintaining its generating and transmission facilities. Over the past 10 years, the ratio of expenditures for maintenance to total revenues from power sales for investor-owned utilities averaged nearly two-thirds higher than that for federal utilities—7.2 percent versus 4.5 percent (see Figure 4). The average ratio over that period for publicly owned utilities was 6.8 percent. That difference is not accounted for by the large number of hydropower facilities in the federal program; even the TVA, which generates more than 80 percent of its power from coal, nuclear energy, and natural gas, spends only about 5 percent of its revenues on maintenance. Indeed, the disparity in maintenance

3. Bonneville Power Administration, *Columbia River Power for the People: A History of Policies of the Bonneville Power Administration*, DOE-BP-7 (Portland, Ore.: no date).

costs per unit of power generated by federal and other utilities is even greater than those ratios suggest, because federal agencies—other than the TVA—generally sell electricity at a lower rate.

One consequence of inadequate spending on maintenance is an inability to generate and transmit power at design capacity. Data from the past five years showing differences between the power output per unit of generating capacity for federal and nonfederal hydropower show the potential for raising federal output (see Table 6). Over that period, nonfederal dams produced an average of 20 percent more electricity per unit of capacity than did dams supplying the power marketing administrations. That particular measure of efficiency suggests that in 1995, when rainfall and reservoir levels were at or near normal in most parts of the country, PMA hydropower sales could have been more than 30 percent higher if federal dams had operated at the same utilization rates as nonfederal dams. (More precise estimates of the generating potential would require additional information about differences in water flows for individual federal and nonfederal dams. Those differences stem from the availability of local water and the constraints of nonpower activities on operators.)

Figure 4.
Ratio of Maintenance Expenditures to Power Revenues for Federal, Publicly Owned, and Investor-Owned Utilities, Calendar Years 1986-1995



SOURCE: Congressional Budget Office using data from the 1986-1995 issues of Energy Information Administration, *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*, DOE/EIA-0437/2, and *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437/1.

Table 6.
Ratio of Production to Operable Generating Capacity for Federal and Nonfederal Hydropower Producers, Fiscal Years 1991-1995 (In percent)

	1991	1992	1993	1994	1995
Federal Producers					
Tennessee Valley Authority	52.7	47.5	53.8	55.9	48.4
Power marketing administrations					
Bonneville	51.7	38.6	38.9	36.0	42.5
Southwestern	27.3	37.7	49.2	39.3	41.0
Southeastern	30.7	27.1	34.4	30.8	27.2
Alaska	45.8	39.1	43.5	32.0	43.9
Western Area	26.4	23.8	24.6	28.4	34.0
Average for All Federal Producers	41.3	33.4	35.2	33.6	38.7
Average for All Nonfederal Producers	44.7	43.1	45.8	39.6	51.4

SOURCE: Congressional Budget Office using information from the Army Corps of Engineers, the Bureau of Reclamation, and the Energy Information Administration.

NOTE: Ratios are calculated as net generation for the year (in megawatt-hours) divided by the product of the manufacturer's specified capacity (in megawatts, for conventional hydropower) and 8,760 hours.

The experience of the Bureau of Reclamation adds evidence of the potential economic gains from greater spending at existing generating facilities. As long ago as 1977, the General Accounting Office recommended that Reclamation upgrade the generating capacity of existing power plants.⁴ Power output can be raised by increasing the capability of penstocks (gates for regulating water flows), turbines (for using water flows to turn generators), generators, transformers, and transmission systems. For example, the amount of electricity from many old generators could be increased by re-winding their armature windings. (Much of the additional capability would supply only peak demand because year-round water flows still affect output.)

4. General Accounting Office, *Power Production at Federal Dams Could Be Increased by Modernizing Turbines and Generators*, PB 269 2254 (March 16, 1977).

Reclamation did not begin to pursue those recommendations until 1990. By 1995, it had raised, or was in the process of raising, the generating capacity of 55 power-generating units at 14 different power plants.⁵ Before the work began, those units accounted for 773 megawatts of manufacturer's specified capacity, or about 6 percent of the total capacity of the 190 generating units at Reclamation's 52 power plants.

The capacity from those upgrades cost much less than the capacity that newly constructed units could have provided. In 1991, Reclamation estimated that the total contract cost for the upgrades it performed between 1978 and 1995 was \$154 million—about \$9 million a year. For the projects it had completed by 1991, that small effort yielded an additional 1,137 megawatts of peak capacity (roughly the size of a large nuclear power plant) at a cost of only \$49 per kilowatt (or, accounting for inflation since that time, about \$55 per kilowatt today). That figure compares very favorably with cost estimates for the other sources of additional capacity. In 1995, several gas-turbine plants came into service at an average cost of \$333 per kilowatt, one small hydroproject cost \$761 per kilowatt, and a large coal plant cost \$1,366 per kilowatt.⁶

New Competition Is a Mixed Blessing for Federal Power Agencies

Federal power agencies are facing more competition in wholesale markets. Competition generally benefits consumers, bringing lower rates and better service. But for federal power agencies, greater competition may

mean lost customers and lower revenues. Exposing the federal power agencies to that kind of competition makes the cost of inefficient production clear and raises the cost of continuing government ownership. Sustaining the status quo would probably require increased support from taxpayers. That support would come only at a high political cost, particularly in today's tight budgetary situation.

Even so, increased competition can have a positive effect—namely, that the incentives of federal managers and policymakers to improve efficiency are made much stronger. Competition leaves less latitude for inefficient operations in the public (or the private) sector. Accordingly, the federal agencies involved, as well as the Congress, see more clearly the need for improvements.

The potential for new competition that federal suppliers could face is already strong in some markets. For example, the rates that the Tennessee Valley Authority charges its preferred customers (publicly owned utilities and cooperatives) are higher than the amount that investor-owned utilities nationwide charge that same class of distributors (4.2 cents and 3.8 cents per kilowatt-hour, respectively). The fact that all federal sales to preferred customers take place at the average rate also opens opportunities for private utilities and independent suppliers to underprice federal agencies, especially for interruptible and off-peak power. The Bonneville Power Administration has already encountered such competition from nonutilities in the Northwest. In response, it has proposed lowering rates (or guaranteeing long-term rates). The BPA is also working to contain its costs for power it purchases, for the subsidies it provides to some investor-owned utilities, and for the environmental programs it supports, in order to avoid losing customers.⁷

5. Bureau of Reclamation, *Hydropower 2002: Reclamation's Energy Initiative*, Technical Document (November 1991).

6. Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities, 1995*, DOE/EIA-0437(95)/1 (December 1996), Table 4.

7. See the 1995 annual report of the Bonneville Power Administration. Also see the *Comprehensive Review of the Northwest Energy System: Final Report* (1997), a report prepared by a working group appointed by the governors of four northwestern states, available at <http://www.newsdata.com/enernet/review/document/bull27doc1.html>.

Options for Changing the Federal Role

The specter of market failures that originally prompted the U.S. government to enter the business of supplying electric power has faded over the past 60 years. During the same period, problems stemming from government failures in the power industry have raised the costs of that supply. In the near future, growing competition in power markets threatens to erode the customer base of the federal power agencies and contribute to higher average costs of government production. Perhaps it will promote even greater inefficiencies in the supply of federal power.

Given those circumstances, many policymakers question whether the government should stay in the power business. This study's analysis of the diminishing benefits and high costs of government production examines arguments for reforming the federal power program or transferring its ownership. Removing the government from the power business would be consistent with and could bolster other steps that the Congress has taken toward deregulating energy markets and reducing government interference in market operations. Moreover, ending federal support for its power programs could contribute to long-term budgetary savings.

The Congress has three basic options for change. First, it may legislate specific remedies to correct failures of the power program arising from the management structure, pricing practices, and uncompetitive marketing that characterize the program. Second, the Congress may decide that federal ownership is no longer necessary, in which case it could transfer, or devolve, to local governments the responsibility for running all or parts of the program. Third, as an alterna-

tive to devolution, it may decide to privatize all or parts of the program. The federal government has pursued each of those options on a limited scale in past efforts at reform.

Of the three options, privatization may offer the nation the greatest opportunity to fully realize gains in efficiency. But each option has drawbacks, and depending on how it is implemented, each option could be equally successful.¹ In particular, since circumstances may differ, any option—including keeping things as they are—that may be most appropriate for one agency might not be best for the others. Even within a single power agency, optimal solutions to existing problems may vary.

Can Legislative Remedies Enhance Efficiency?

A number of legislative changes could enhance the efficiency of all or parts of the federal power program without requiring a change in ownership. The Congress could make those changes solely to improve current management or help raise the market value of power assets before selling them. This study identifies a list of remediable problems related to the managerial struc-

1. For a review of empirical studies comparing private and public enterprises, see John Vickers and George Yarrow, *Privatization: An Economic Analysis* (Cambridge: MIT Press, 1988). For a review of different regulatory approaches for natural monopolies, see articles in Richard Schmalensee and Robert D. Willig, eds., *Handbook of Industrial Organization*, vol. 2 (New York: North-Holland, 1989).

ture of programs, pricing practices, and obstacles the market poses to competitive pricing. It also analyzes options for reorganizing the power marketing administrations as government corporations along the same lines as the Tennessee Valley Authority.

Remedies for Managerial Structure

Among the proposed managerial changes for the power marketing administrations is one for ending the division of labor between the Bureau of Reclamation and the Corps of Engineers on the producing side of the program and the PMAs on the selling side. With that change, the PMAs would assume full responsibility for operating and maintaining power units on federal dams or, alternatively, Reclamation and the Corps would take on the responsibility for marketing. Accompanying that unification of responsibilities would be changes in the budgeting process that would give each agency full discretion to allocate power revenues between investment in new capacity and spending on operation and maintenance. (Budgeting for power activities is currently subject to limitations imposed by overall spending plans for parent agencies and budget allocations for different Congressional committees.)

Some precedents for that action come from the Tennessee Valley Authority, which already has a unified budget and more autonomy over operating revenues than do the PMAs. Similarly, under the Energy Policy Act of 1992, the Bonneville Power Administration may use some revenues to fund directly certain operating expenses of the Bureau of Reclamation and the Corps of Engineers. In fiscal year 1995, the BPA directly funded \$20 million of hydropower investments by other agencies.² And the Western Area Power Administration has some discretion over revenues from selling power from the Hoover Dam and other projects.

As the example of the TVA emphasizes, simply unifying the management responsibilities and budgeting for PMA operations would not alone solve all the problems of government ownership. For both the TVA and the PMAs, current earnings (or financing tied to future earnings) should limit agency spending. In particular, the prospect of higher revenues should signal the need

for expansion, and lower revenues should call for closing the facilities.

Beyond such market constraints, it would be necessary to impose independent oversight of spending by power agencies. That oversight should include the authority to occasionally divert income from power to other federal needs when it seems evident that the public can benefit from spending those funds elsewhere—just as private businesses have the discretion to distribute profits to shareholders or to invest in new lines of business. (A corollary of revising the managerial and budgetary structure of the power agencies would be that the Congress would have to initiate or raise its appropriations for nonpower activities that now depend on power revenues.)

Furthermore, program efficiency would benefit from independent oversight of power rates, including the imposition of "ironclad" schedules for repaying capital investments. The ability of the power agencies to exercise discretion in withholding certain costs from their rate bases—for example, by classifying projects that will never be completed as "works in progress" to keep them out of the rate base—removes the financial burden of poor investment decisions and indeed makes it easier for federal agencies to make unprofitable decisions. In exchange for exclusive rights to market power in certain regions, all nonfederal utilities are subject to some oversight by local public utility commissions or the Federal Energy Regulatory Commission. Independently, the Securities and Exchange Commission reviews the financial reports of all private utilities that are publicly traded.

Remedies for Pricing Practices

As competition begins to dictate price setting in wholesale markets, the need for public oversight of power rates—including federal rates—will diminish. But additional changes in the way federal agencies set rates will become necessary.

Specific changes in pricing practices would enhance efficiency: the TVA and the PMAs could set uniform power rates for all customers on the basis of the marginal costs of supplying power. That marginal cost—the price of the last and most expensive unit of power (produced or purchased)—should reflect the

2. *Budget of the United States Government, Fiscal Year 1998: Appendix*, p. 482.

value of water resources and power assets when applied to their best use. Such opportunity costs may reflect the value of diverting water for nonpower purposes or saving it for later use. Efficiency-enhancing changes in federal pricing could raise power rates for some users but, more important, would improve signals for all producers and consumers, letting them know how much power to supply and use.

If pricing was revised, the average for all federal sales would probably rise. (For example, the Congressional Budget Office estimates that the additional receipts that would result from raising PMA power rates to market levels could total \$210 million a year—including the termination of pricing subsidies for some investor-owned utilities in the Northwest.)³ The income from a few high-cost projects may decline with such revisions, so that some federal investments would then appear less valuable. The value of assets owned by nonfederal suppliers who currently benefit from the ability to underprice the TVA or the PMAs may also diminish.

A similar revaluation is already plaguing investor-owned utilities that face growing competition from low-cost suppliers and changing federal regulation: assets that were profitable in the earlier market environments now appear as "stranded costs."⁴ Such stranded costs are already lost, and their presence does not affect current operating or investment decisions. The only issue is one of equity—whether anyone should compensate utility owners for such losses. Equity concerns may also arise with federal stranded costs—in that case, between the general, taxpaying public and local purchasers of federal power.

Remedies for Uncompetitive Market Structures

Finally, legislative changes to enhance the competition in wholesale markets nationwide would end price dis-

crimination by the PMAs and the TVA and authorize the FERC to regulate open access to federal transmission lines on the basis of set fees for transmission services. (The Energy Policy Act of 1992 currently exempts the BPA and the TVA from the requirement to grant open access to their transmission systems, although the BPA is taking steps to comply voluntarily.) Those changes would end the preferential pricing and sale of power to publicly owned utilities and cooperatives and, for the TVA and the BPA, to large industrial customers. They would also end regional preferences.

For the Tennessee Valley Authority, ending regional preferences would mean taking down the TVA "fence," which restricts the movement of power into and out of the TVA service area. (The barrier arose when the original Tennessee Valley Authority Act limited the ability of private businesses to develop power resources in the Tennessee River basin and when the 1959 amendments to the TVA act prohibited the TVA from selling power beyond its historical customer base.) With those changes, the TVA could sell more power and therefore use its base-load capacity more fully. (Base-load capacity is the generating equipment that normally operates to meet the around-the-clock requirements of consumers.) Ending regional preferences would also enable others to compete in the TVA's service area.

Like changes in pricing practices, changes in the competitive structure of federal agencies may also affect the value of certain power-generating and transmission facilities. In particular, if the TVA and the PMAs were free to market in a broader region, the problem with stranded costs for nearby utilities could worsen. Under a policy of open access, however, the federal agencies may also face such problems if they are not able to combine all costs—including those for already canceled projects—in their power rates.

Under the terms of FERC Order 888, which regulates the open access of transmission systems, some wholesale customers may have to compensate their old supplier for stranded costs if they change to a new supplier. The FERC order, however, does not apply to the TVA, but that agency has already successfully sued one utility that wanted to leave its system to recover its stranded costs.

3. Congressional Budget Office, *Reducing the Deficit: Spending and Revenue Options* (March 1997), pp. 219-220.

4. Oak Ridge National Laboratory, *Estimating Potential Stranded Commitments for U.S. Investor-Owned Electric Utilities*, ORNL/CON-406 (January 1995); Moody's Investors Service, "Stranded Costs Will Threaten Credit Quality of U.S. Electrics," *Global Credit Research* (August 1995).

Setting Up Government Corporations to Sell Power

A separate set of legislative remedies would restructure the PMAs (including the assets of Reclamation and the Corps) as government corporations. But such changes might not address all the issues necessary to create an efficient enterprise. The intent of many of those proposals is to relieve federal programs of specific cost burdens and give them more spending autonomy. For example, the National Academy of Public Administration (NAPA) recommended exempting a new Bonneville Power Corporation from 14 federal laws.⁵ Those exemptions were related to restrictions of the appropriation process (and overall limits on discretionary spending), federal procurement processes, personnel policies, and requirements for competitive contracting.

The exemptions, however, do not address the fundamental problems of the PMAs. The Bonneville Power Corporation that the NAPA envisioned would not assume direct responsibility for the current functions of the Bureau of Reclamation and the Corps of Engineers. It would also not be fully independent of federal funding. Since borrowing from the Treasury could continue, there would be none of the market discipline that competitive pricing and financing impose on private businesses. Furthermore, there would be no new restrictions to address the corporation's discriminatory pricing practices and public access to transmission systems. The experience of the Tennessee Valley Authority, which is already organized as a government corporation and benefits from many of the legislative exemptions that the NAPA recommends for the BPA, bolsters the observation that corporate status is not a panacea for inefficiency.

Can Local Governments Manage Better?

In one of the three options for change, the federal government would sell or give power-generating and trans-

mission facilities to states or local communities. Under the President's "reinventing government" initiative, the Bureau of Reclamation has already developed plans to shift responsibility for some water projects to local jurisdictions.⁶ The goals of devolution do not require a change of ownership, only an arrangement that grants local governments long-term control over power assets.

Local Incentives for Efficient Management

Local governments may have a greater incentive to make more changes to enhance efficiency in the federal power program than would the federal government. For decades, the federal government has been able to sustain the subsidies and inefficiencies inherent in its power program, because the costs associated with the current power program are small in relation to the overall federal budget and are spread over the accounts of several different agencies. The costs that one region of the country bears in supporting another region do not show up clearly in unified accounts.

By contrast, any local government (or publicly owned utility) that might take over a portion of the federal power program may face significant political and economic pressures to reform managerial practices, pricing incentives, and uncompetitive marketing practices. For example, it could be politically difficult for a local government to subsidize indefinitely one part of its citizenry at the expense of others on the same scale that the federal government supports power. On local ledgers, such cross-subsidies would be more visible than they are now—especially with open and competitive pricing.

Moreover, as competition grows in wholesale power markets, publicly owned utilities that discriminate against some customers in order to subsidize others will be increasingly likely to lose their high-priced customers to independent power producers. (Under the Energy Policy Act of 1992, those independent producers would have full access not only to transmission systems formerly belonging to the government but also to all the distributors that the government now serves.) Utilities that have inflated their power rates to help re-

5. National Academy of Public Administration, *Reinventing the Bonneville Power Administration* (Washington, D.C.: NAPA, December 1993); General Accounting Office, *Government Corporations, Profiles of Recent Proposals*, GAO/GGD-95-57FS (March 1995).

6. Bureau of Reclamation, *Framework for the Transfer of Title, Bureau of Reclamation Projects* (August 7, 1995).

coup poor investments or pay off debts would be similarly vulnerable. Compared with the current management structure, local ownership would have the advantage of unified management of production and sales. Those activities would be subject to the disciplines of competitive pricing and financing.

There are some historical precedents for having local governments manage power facilities. Local governments have not played a big role in the long-distance transmission of power, but they do own generating capacity. Nonfederal, publicly owned utilities currently generate about 10 percent of the nation's electricity. A few of them also have specific experience with hydropower. Publicly owned utilities hold three of the nation's 12 largest hydropower plants, including one at Niagara Falls and two in the Columbia River basin. Nonfederal entities, including local governments, hold FERC licenses to operate power units on 45 Reclamation facilities and 67 Corps facilities—for a total of about 2,000 megawatts of generating capacity.⁷ And until passage of the Hoover Power Plant Act of 1984, a municipal utility participated in the operation of power facilities at Hoover Dam.

Potential Concerns About Devolution

A number of concerns surround the potential benefits of devolution. The first is whether local control would indeed be less costly than federal control. Any conclusion of gains in efficiency from local control presumes that local utilities would face greater pressure for reform than would the federal government. Much of the impetus for that reform would come from the emerging competitive structure of power markets. But power markets are not yet fully competitive, especially at the retail level. Local utilities therefore remain relatively free to pursue social objectives that conflict with efficient power operations.

A second concern is related to the assets that local governments would acquire—and what would happen to the assets they did not take. Publicly owned utilities have invested little in their own power-generating capacity and have generally avoided acquiring transmis-

sion capacity beyond what is necessary to hook up to regional grids. Indeed, many public charters prohibit such extensions of service. Individual utilities and rural communities may not have the financial resources or incentive to own and operate capacity that exceeds their local requirements. Those communities may be interested only in acquiring facilities that are already directly serving their residents, although they may be able to skirt that obstacle by joining other communities in forming consortia to buy federal assets.

Potential for Conflict Between Federal and State Regulators

A final issue, as local governments acquire capacity to supply power in wholesale markets, is the relationship between federal and state regulations. In regulation, the basic division of labor gives the Federal Energy Regulatory Commission oversight of interstate wholesale rates and the state and local authorities oversight of retail rates and customer service. That division has prevailed over the years largely because local governments have not been very active in supplying power to the wholesale market. Thus, the interstate wholesale market has effectively included all wholesale transactions.

Some conflict between federal and local regulators surfaced in the past decade as the number and influence of nonutility suppliers increased—a trend that has effectively moved some local sales away from local jurisdiction. The devolution of federal power assets could cause additional conflict by increasing the number of local governments supplying power to wholesale markets. As long as those sales are wholly within a state, local governments may assert jurisdiction. But in the integrated regional markets of today, where many investor-owned utilities operate in multiple states, such purely intrastate transactions may be rare. States may not welcome broader federal jurisdiction over local rates.

Can Private Businesses Manage Better?

Any of three fundamentally different ways of altering the management of federal power assets can be called

7. From data reported in Bureau of Reclamation, *Hydropower 2002: Reclamation's Energy Initiative* (November 1991); and a personal communication to the Congressional Budget Office by the Operations Branch of the Army Corps of Engineers (May 1995).

privatization. The first would transfer, without restriction, the ownership of federal power assets to private companies. Those assets would include generating and transmission facilities and all current customer contracts. (That transfer could encompass the lease of exclusive, long-term rights for the operation and upkeep of federal facilities, with the government retaining title and the companies retaining the profits.)

A second approach to privatization would transfer ownership title—or lease operating rights—subject to significant restrictions on who the new owners could be (or to whom they could resell), what the sale price could be, or what the conditions for future power sales could be.

A third approach would engage private companies as contractors who would operate federal facilities under the general control of federal managers. That arrangement is commonly termed "GOCO," or government-owned, contractor-operated.

Privatization Options Encompass a Broad Range of Federal Control

In each approach to privatization, the government has decided not to produce power but still retains some control over supply. Only the degree of control differs. Privatization by the unrestricted transfer of title would go farthest toward removing the federal government from power markets. But even there, some government control would remain in the form of existing federal and local regulation and tax incentives—controls that now apply to private companies.

Privatization by granting exclusive access—for example, the long-term lease of privileges to build and operate power facilities on federal dams—is generally equivalent to transferring title except that the ownership rights are conditional. Leasing for a finite period, the government retains an option to resume management in the future. Such limits may diminish the value of federal assets to private companies and perhaps reduce incentives to make long-term investments in those facilities. But government would also retain some liabilities, which could both enhance the value of the facilities to the private sector and reduce the benefits that a sale would bring to the government. Liabilities could

arise from structural failures or the silting up of reservoirs with age.

Along with the terms of sale or lease, the government could impose additional restrictions. At a minimum, the new owners may be subject to the requirements of laws affecting the operation of dams. FERC licensing currently requires operators to manage river flows and lake levels to comply with community recreation needs, flood control and navigation programs of the Corps, and statutes concerning fish and wildlife, historical sites, and water quality. For hydropower projects, FERC licensing can also establish a share of power output that must be sold to public entities.

The terms of sale may also grant preferential treatment to certain purchasers. For example, to continue federal support to preferred customers, the Congress may grant the current customers a favorable sales price, terms of finance, or simply the right of first refusal in any federal sale. Or, to protect the consumers of federal power more directly, the Congress could restrict a new owner from raising rates beyond some level or within some period.

Restrictions on the operation of hydropower facilities may diminish the value to new owners but could still be socially efficient because regulation through FERC licensing of dams is a cost-effective way to alter private incentives. Limiting the list of potential purchasers or holding down the sales price to certain purchasers may convey a windfall to new owners but would not alter their incentives to set power rates or operate power facilities efficiently. In the extreme, however, restricting the ability of new owners to set power rates at market levels or imposing service requirements could dampen their incentives to invest in maintenance and capital improvements.

Privatization by creating a government-owned, contractor-operated organization would enable the government to retain control over volumes, prices, and quality but still gain some of the managerial efficiencies of private operation. Separate legislative remedies would be necessary, however, to enable government-owned, contractor-operated facilities to correct problems deriving from government ownership. In the extreme, a GOCO could be indistinguishable from current federal management.

Restrictions on Privatization Versus Efficiency Gains

Privatization by transferring ownership would produce full gains in efficiency only if the sale or lease imposed no restrictions on operations beyond those that already applied to nonfederal power suppliers. Gains in efficiency would also require imposing no restrictions on the assets or bundles of assets that private companies could acquire. A government sale of the transmission systems of the PMAs but not the power-generating units of Reclamation and the Corps (or the rights to operate those units) could impede any movement toward managerial accountability and marginal-cost pricing. Social efficiency could also require subjecting buyers of hydropower plants to FERC licensing.

How quickly improvements in pricing incentives take place with new ownership may also depend on who acquires the federal facilities. For example, under privatization, independent producers (including qualifying

facilities, as defined by the Public Utility Regulatory Policy Act) would base prices immediately on the marginal costs to the market. The adjustment to market rates would be relatively fast, unless the terms of sale restricted the ways in which the owner set prices (see Table 7).

Publicly owned utilities, cooperatives, and investor-owned utilities—which are required to set rates that yield allowable returns on their capital investment—would adopt marginal-cost pricing slowly, as the pressures of wholesale competition grew and the value of their capital base adjusted accordingly, or as public utility commissions installed more flexible pricing. Within that group, however, cooperatives and investor-owned utilities may adjust more quickly under privatization than publicly owned utilities under devolution. Many local governments use surplus revenues from public power sales to support other public services or supplement general revenues. In a competitive environment, however, power rates would more closely match costs, and local governments would have to compensate for a

Table 7.
Comparison of How Fast Current Federal Rates Adjust to Market Rates
for Different Reform Options and Types of Ownership After Reform

Reform Option	Independent Power Producer	Regulated Utilities			
		Publicly Owned Utility	Coop- erative	Investor- Owned Utility	Federal Utility
Legislative Remedies					
Unified management	*	*	*	*	Medium
Marginal-cost pricing	*	*	*	*	Fast
Competitive market structure	*	*	*	*	Medium
Government corporation	*	*	*	*	No Change
Transfer to Local Control	*	Slow	*	*	*
Privatization					
Unrestricted sale (or lease)	Fast	Slow	Medium	Medium	*
Restrictions on sale					
Sale to current customers	*	Slow	Medium	*	*
Sale below market value	Fast	Slow	Medium	Medium	*
Cap on future power rates	Slow	Slow	Slow	Slow	*
Government-owned, contractor-operated	*	*	*	*	No Change

SOURCE: Congressional Budget Office.

NOTE: * = not applicable.

Box 1.**The Licensing of Nonfederal Hydropower Projects**

The Federal Energy Regulatory Commission (FERC) issues licenses authorizing the construction, operation, and maintenance of hydropower projects on navigable waterways, public lands, or streams where the federal government has jurisdiction. The FERC also licenses power projects that nonfederal interests may construct on federal dams. Licenses are valid for periods up to 50 years. Many of the projects that the Federal Power Commission (the FERC's predecessor) approved in the 1930s are now coming due for relicensing.

Several laws govern the licensing of nonfederal dams. The Federal Power Act of 1935 directs the FERC to evaluate a proposed project for safety, adequacy of design, and economic feasibility, consistent with the comprehensive development of the river basin

in which it is to be located. The Electric Consumers Protection Act (ECPA) of 1986 further directs the agency to give equal weight in its licensing decisions to nonpower values, such as energy conservation, fish and wildlife, and recreation. As part of its decisionmaking process, the FERC also conducts reviews under the authority of the National Environmental Policy Act of 1969 to identify environmental threats. Exemptions from the licensing requirement are generally available under the Energy Security Act of 1980 for plants with generating capacities of 5,000 kilowatts or less and, under ECPA, for municipal projects generating up to 40,000 kilowatts. Legislation authorizing the sale of the Alaska Power Administration exempted the new owners of the APA facilities from the licensing requirement.

diminishing surplus from power operations by raising other taxes or fees or by cutting services—measures that local politics could make difficult.

Restructuring federal power agencies as government corporations or GOCOs may give the appearance of privatization, but without independent legislative remedies, it would not make pricing more efficient. Such organizations would be subject to the same managerial incentives, pricing practices, and anticompetitive structures that currently impede the efficiency of federal agencies.

Concerns About Market Failures

The potential for inefficiencies from technical or behavioral market failures that current regulations do not address causes concern about changes in federal ownership. One such worry is that private companies may use parts of the federal transmission system to acquire regional market power. Whether that concern is resolved could depend on the open access rules that the Federal Energy Regulatory Commission has written under the authority of the Energy Policy Act of 1992; full access to transmission lines at nonprohibitive rates would preclude efforts to build regional monopolies. Direct controls by new regulations (of prices, product quality, working conditions, or service requirements) or

indirect controls by taxes and subsidies may be required to correct market failures.⁸

Concerns About Ending Exemptions of Federal Programs from Federal Laws

The transition from federal to private ownership also raises concerns about the fact that federal agencies have never been subject to the same regulations as private or local government owners. In particular, Reclamation and Corps dams have not been subject to the licensing requirements of the Federal Energy Regulatory Commission, even though those dams are generally in compliance with federal statutes.

A licensing process that makes new operators halt production for several years while the FERC completes environmental studies could impede gains in efficiency

8. In "Why Regulate Utilities?" *Journal of Law and Economics*, no. 11 (1968), Harold Demsetz demonstrates how governments may correct the restrictive pricing of a natural monopoly by auctioning franchise rights to operate the monopoly rather than directly regulating the monopoly price. In *Public vs. Private Ownership and Economic Performance: Evidence from the U.S. Electric Power Industry*, Harvard Institute of Economic Research, Discussion Paper No. 1712 (February 1995), John E. Kwoka Jr. suggests that the incentives from tax exemptions for private utilities may be equivalent to incentives from government loans and preferential power supplies for public utilities and co-operatives.

from privatization or devolution (see Box 1). Any delays or uncertainty accompanying the relicensing process would also diminish the present market value of those dams to their new owners. But if federal agencies have not been maintaining and operating individual dams safely and with regard to such issues as preservation of fish and wildlife, delays that take those projects out of service may actually benefit society.

Who Benefits and Who Loses as a Result of Reform?

Any change in the management or ownership of a federal power program must be accompanied by concerns about equity, because power rates are likely to change. Some rate increases are probable for certain customers and regions of the country where federal power rates are far below market levels. Other power consumers, however, may benefit from lower rates resulting from regionwide gains in efficiency, and taxpayers nationwide may profit from federal savings that reform or new ownership can produce.

This study does not attempt to predict how rates for electric power will change. At least four factors would complicate that task.

- o How much federal power rates will go up depends in part on the nature of reform and, for a sale of power assets, what restrictions the Congress might place on future rate changes.
- o Even within the range of increase that the Congress may allow, gains in efficiency at federal facilities and through a region may diminish cost pressures on wholesale rates. (Gains in efficiency could be related to the investment in maintenance at federal facilities, the expanded availability of hydropower—especially as a low-cost source of power for peak-period demand—and access to federal transmission systems, and the market pricing of electricity.)
- o Except for a few states, the federal share of total power supply and, therefore, the potential for federal rate changes to influence regional wholesale rates is generally small.

- o Because structural changes are now under way in power markets, it is not clear how much of any rise in wholesale power rates could be passed on to retail customers by local power distributors.

However, one can make some observations about the general consequences of new ownership and power rates for the four major groups that would be affected. The four groups are residential and commercial consumers of federal power, industrial consumers of federal power, local utilities that now purchase federal power, and utilities that may purchase federal power assets.

Residential and Commercial Consumers—Small Gains Offset Small Losses

The households and small businesses that purchase electricity from the preferred customers of PMAs will probably pay more for that electricity, and consumers that do not receive PMA power will probably pay less. Consumers of TVA power already pay rates similar to those charged by nearby investor-owned utilities and therefore would probably not see much change in power costs. In general, regardless of who acquired the federal power facilities or what they might pay, the consequences for consumers of federal power would be similar because power rates are likely to change by the same amount regardless of ownership.

Even for retail customers whose rate went up, the increase would not be commensurate with the current difference between federal power rates and market rates for wholesale power. (Wholesale power is what generating utilities sell to local distributing utilities; retail power rates reflect a markup over wholesale rates.) The explanation for the dampening effect on consumer rates has three parts.

First, many of the government's preferred customers already purchase significant amounts of power from investor-owned utilities. Since the average rate that those distributing utilities currently pay for power from all sources is already higher than the federal rate, the change in average power costs they passed on to retail customers would be smaller than any change in the federal rate.

Second, gains in generating and transmission efficiency resulting from reform or new ownership may lower the costs of wholesale power throughout a region. That means that the wholesale rates charged by private utilities may decline, further dampening any change in the average cost of power to distributing utilities.

Third, local distributing utilities may not be able to fully pass through to their customers any changes in wholesale power costs, especially as competition grows in retail markets. The absence of competition has enabled local utilities to hold retail rates significantly above wholesale costs. But if municipal utilities now use power revenues to defray the costs of water, lighting, or other services, any shrinkage of markups—caused by federal reform or growing competition in general—may make local governments raise other taxes or user fees to sustain those services.

Little Change for Industrial Consumers

Industrial customers are concerned with changes in power costs and the value of their investments in power-consuming equipment. Whether or not the industries that now consume federal power would face higher rates (and diminished profitability and investment value) under reform or new ownership would depend on their current rate for electricity.

The aluminum businesses that account for most of the direct industrial sales by the BPA and the TVA already pay rates for power that are similar to those that nonutilities would probably charge them for additional supplies—about 2 cents a kilowatt-hour. It is not clear whether private suppliers today could meet all the demand of those companies at that low cost, but power costs for the aluminum businesses of the Northwest and Southeast would probably not change much if and when federal power programs were reformed or sold. To the extent that those businesses now benefit from federal sales, the competitive position of other aluminum producers throughout the rest of the country—who account for one-half of the nation's supply of aluminum—would improve.

Other industrial firms that purchase power from the preferred customers of the federal power agencies may also see little change in power rates under reform or new ownership if they are already benefiting from market rates as a consequence of wholesale competition and open access to independent suppliers. Those who have not benefited from competition, however, would probably see higher rates. Finally, the industrial customers of utilities that do not get federal power now would probably see lower rates if reform yielded gains in efficiency throughout a region.

Local Distributing Utilities—Gains and Losses

The value of utilities' capital assets may change with the reform or sale of the federal power program. If power rates change, the profitability of current operations and the value of existing capital investments throughout the power industry will change as well—regardless of who the new owners might be or what they might pay for federal facilities. The market value of capital simply reflects the present value of its future earnings, discounted by a required rate of return. Any policy that lowers future earnings necessarily lowers market value. Higher wholesale rates would probably depress the value of the distribution assets of preferred customers for federal power.

Other distributing utilities in the region—the non-preferred utilities and their nonfederal customers—could see the value of their investments enhanced by the wider availability of hydropower. Hydropower is especially valuable as a quick, flexible source of electric power. Suppliers who have access to hydropower can avoid calling on expensive steam plants to meet temporary, or peak, surges in demand. Any increase in the efficiency of regional power networks as a result of reform would also benefit nonfederal customers. The consequences for owners of generating and transmitting utilities formerly supplying the nonpreferred customers of the government and those for nonfederal customers would be mixed: the value of their assets could either decline because of lower market rates throughout the

region or rise as a result of opportunities for competing in a bigger market.

Windfalls for Utilities That Purchase Federal Assets Depend on Below-Market Sales Price

How utility owners benefit from reform would also depend on whether they acquire federal assets and what they pay. A local government or private utility that acquires federal power assets for any cost that is less than their full market value would receive a significant windfall—at the expense of the federal taxpayer.

For example, a sales price that reflects a low outstanding debt for some federal power agencies—a largely arbitrary figure—would certainly convey such a windfall. If the current preferred customers are the purchasers, such a windfall could partially offset or even exceed any losses attributable to rising wholesale rates and the declining value of their distribution assets. By contrast, the highest bidder in an open competition, who pays the full market value, would receive no windfall. Opportunities would exist for individual gain in such a competition as a result of restrictions on the participants or the sales price.

The Value of Federal Power Assets to the Private Sector

Whether the goal of change is to promote economic efficiency, balance the budget, or simply terminate a federal role that no longer serves an important social purpose, no single option for reforming federal power programs need be the best. What might make most sense for one power agency—legislative reform, devolution, privatization, or even no change—may not be good for others. Even within a particular agency, different solutions for different power projects may be desirable. Any choice among solutions will ultimately reflect many considerations, including budgetary consequences, economic efficiency, and equity among the competing interests of different local and national groups. The focus of this study is on budgetary considerations, but a starting point for understanding the implications of reform for the budget, the economy, or special interests is that of identifying the assets that are at stake and how the private sector might rate them.

Three basic considerations should influence decisions about which, if any, projects to keep, devolve, or privatize.

- o What are the assets that the government could transfer by devolution or privatization?
- o What is the potential market value of those assets?
- o What impact would restrictions on transfers (such as placing limits on future power rates) or on the transfer price (such as covering the value of outstanding debts) have on the market's valuation?

The recently authorized transfer of the assets of the Alaska Power Administration to local control represents a case study of how the Congress can decide on what to sell, to whom, and for how much (see Box 2).

The Congressional Budget Office estimates that based on the present value of net cash flow, the market's valuation of all federal power assets (including those of the Alaska Power Administration) is between \$45 billion and \$62 billion. Those estimates assume an efficiency gain with private management and no special restrictions on the terms of sale. The range of values reflects uncertainty about the potential future growth of power rates.

Selling assets, however, is not the same as reducing the deficit. In selling an income-producing asset, the government trades the future income that asset will generate for a lump-sum payment today. An asset sale would be justifiable on the basis of budgetary savings only if that payment, plus the present value of any increase in tax receipts after the sale, was greater than the present value to the government of future net receipts from retaining the asset.

Which Assets Are at Stake?

Views vary about what assets the Congress must transfer to new owners if it pursued devolution or privatization. In particular, it is important to distinguish power assets from associated, nonpower assets; physical as-

Box 2. Selling the Alaska Power Administration

Plans to transfer federal power assets in Alaska to state and local ownership have a long history.¹ The transfer has been under active consideration since 1989, when the Alaska Power Administration (APA) signed purchase agreements with the state of Alaska and local utilities for the transfer of two power systems: the Eklutna project (serving the Anchorage region) and the Snettisham project (serving Juneau). Legislation authorizing the transfer (the Alaska Power Administration Asset Sales and Termination Act), became law in November 1995. The last federal barrier to the transfer—authorization for the state of Alaska to finance its part of the purchase with tax-exempt bonds—became law in August 1996. The final conveyance, before which the purchasers must secure financing, will not take place until late 1997 for Eklutna and early 1998 for Snettisham. The sale price should total about \$85 million.

In some respects, the APA sale was relatively straightforward. The assets for sale were clearly defined: hydropower projects with their generating equipment, transmission lines, and administrative and maintenance facilities. The projects are located in small river basins that do not involve irrigation or navigation. Environmental considerations could be addressed in an agreement between the Fish and Wildlife Service and the purchasers without having to go through a lengthy licensing process with the Federal Energy Regulatory Commission. With the exception of the Tennessee Valley Authority, the APA is the only power agency that owns its generating capacity. Therefore, a sale would not have to address the disposition of assets for separate agencies. Moreover, the program consisted of two separate systems with no mutual links to broad power grids. Thus, the current customers for each system were the

only parties expressing interest in the sale. Passage of the legislation authorizing the sale required many years, however, even with the full support of Alaska's Congressional delegation.

In other respects, the conveyance demonstrated many of the complications that might arise when other federal programs are transferred. Local political concerns largely dictated the terms of the sale. For example, the terms limited purchasers of the assets to a system's current customers. The buyers of the Eklutna project are the Anchorage Municipal Light and Power Company (a publicly owned utility) and the Chugach and Mantanuska Electric Associations (cooperatives). The nominal purchaser of Snettisham is the Alaska Industrial Development and Export Authority (a state agency), but the state has contracted with the Alaska Electric Light & Power (an investor-owned utility) to operate the project—effectively transferring long-term control to that entity. In effect, the sale was one part devolution and one part privatization—demonstrating that the Congress does not have to choose between those two options.

The sales prices reflected equity considerations, not market efficiency. The general basis for the price of each of the projects was the present value of the outstanding debt of the agency plus interest, not the market value. The resulting acquisition costs will establish a rate base for each of the new operators that, given standard rate-of-return pricing, will probably have a minimal impact on Alaskan power consumers. The sale does not try to maximize the return to U.S. taxpayers. The present value of future debt payments reflects the low interest rates on that debt and the greatly deferred payment schedule; for example, the nominal value of outstanding debt for the APA in 1995 was \$166 million, not \$85 million. Beyond possibly accepting a below-market offer, the federal government subsidized the sale in two ways. Alaskans benefited from the Snettisham sale because the debt basis for the sales price excludes a part of the construction costs for the Crater Lake portion of the project, and the project will be financed with tax-exempt bonds.

1. A discussion of the agreements to sell the assets of the Alaska Power Administration appears in General Accounting Office, *Federal Electric Power: Views on the Sale of Alaska Power Administration Hydropower Assets*, GAO/RCED-90-93 (February 1990). Also see Alaska Power Administration, "Brief History of Divestiture," available at ptialaska.net/~apa/divchron.html.

sets from intangible assets that may also have value to a new owner; and finally, individually transferable assets from assets that must be kept together to operate efficiently.

Distinguishing Power Assets from Nonpower Assets

Many of the federal governments' dams, river locks, and reservoirs serve multiple purposes in addition to supporting the generation of power. The power turbines and generators inside a dam are clearly power assets, as are power transmission systems: they serve no direct function other than supplying electricity. But the overall design of a water project may also support diversions of water for such purposes as irrigation, flood control, navigation, recreation, and fish migration. The use of power facilities at such a project can affect the project's nonpower goals. Even when a project of the Bureau of Reclamation or the Corps of Engineers narrowly supports power generation, the project may be financially tied to nonpower activities. In many cases, the Congress has intended that a project's power revenues help pay for regional nonpower activities through the allocation of capital costs or the explicit transfer of funds. The issue of financial interdependence of power and nonpower activities pertains mainly to the power marketing administrations, because the Tennessee Valley Authority receives separate appropriations for its nonpower activities. The TVA does manage multiple-use water projects, however, and its nonpower appropriations for the stewardship of the river system may help defray some costs of generating hydropower. In fact, that cost relationship may be pertinent now because the TVA has proposed that the Congress end its nonpower appropriation and transfer those programs to other agencies or local governments.¹

Although power and nonpower activities may be physically or financially related, it is not necessary to devolve or privatize all the physical assets associated with a multiple-purpose project in order to change the role of the federal government in supplying power. Many options are available for effectively separating power from nonpower functions. For example, the gov-

ernment could sell the power-generating equipment of a dam, grant the new owner access rights to the related federal facilities and land, and allow the Bureau of Reclamation or the Corps of Engineers to maintain responsibilities for managing water flows, public access, and water sales. Or the government could transfer an entire water project—generators, dams, and lakes—but restrict the new owner's management of water flows and access to recreational areas through licensing by the Federal Energy Regulatory Commission and requirements to honor existing contracts for agricultural or municipal water supplies. Other alternatives are possible.

The government need not withhold nonpower assets from a transfer of water projects or totally prescribe the management of nonpower activities by new owners. The new owners may earn income from services that the government now gives away free or otherwise subsidizes, such as the operation of dams and locks to support river navigation. The government currently assesses no direct charges for the use of inland waterways.²

Distinguishing Physical Assets from Intangible Assets

Even when the power activities associated with multiple-purpose projects can be separated from nonpower activities, confusion may arise about which specific power assets are available for transfer. It is useful to distinguish agencies' physical assets (or capital investments) from intangible assets that may also be of value.

The Physical Assets of Federal Power Agencies. The federal government's physical assets that support power supply include the transmission systems of the TVA and the power marketing administrations as well as the power-generating facilities of the TVA, the Bureau of Reclamation, and the Army Corps of Engineers. Transmission systems include power lines and related rights of way, power substations, microwave communication facilities, and other real estate. The TVA's generating facilities that use coal, nuclear fuel, or natural

1. Testimony by Craven Crowell, Chairman of the Tennessee Valley Authority, before the Subcommittee on Energy and Water Development of the House Committee on Appropriations, March 6, 1997.

2. The Congressional Budget Office report *Reducing the Deficit: Spending and Revenue Options* (March 1997), p. 239, estimates the costs of operation and construction for inland waterways at \$2.9 billion for the 1998-2002 period. However, only a part of the inland waterway system—and, hence, of those expenses—is related to facilities that produce power.

gas include all related capital equipment, fuel inventories, and associated land and buildings. Hydropower generating facilities include, as a minimum, the dams' penstocks, turbines, and generators and their related equipment for controlling voltage.

The physical assets that help produce hydropower also include dams, reservoirs, and related real estate, but the transfer of title to those assets would not be a necessary part of devolution or privatization. Conveying the rights to use power-generating equipment at federal sites and to divert water from federal reservoirs for generating power would be sufficient to enable a new owner to produce power profitably.

Intangible Assets That Have Market Value. Although many market valuations focus on the ownership of physical assets, certain intangible assets may also be of great value. The most important intangible assets are contractual rights that may be conveyed to a new owner. Rights to use dams and reservoirs are examples of assets that could be as valuable as title to the physical assets themselves. Rights to serve particular customers may also be valuable.

The only meaningful difference between a transfer of power rights and a transfer of ownership title derives from differences between charges for power rights and the costs of operating and maintaining power facilities. Depending on the terms of transfer, other physical assets supporting the generation of power may become intangible assets. In particular, the right to market the power that Reclamation and Corps facilities produce could accompany the sale of the PMAs in place of direct title to those generating facilities.

The rights to electricity from the nuclear plant operated by the Washington Public Power Supply System constitute an intangible asset of the Bonneville Power Administration. The Congress could transfer just the physical transmission assets of the Tennessee Valley Authority to new owners along with the intangible asset of access rights to the power that a scaled-down TVA would generate from federal facilities. Again, to a new owner, the only important distinction between a transfer of rights to power and a transfer of generating facilities would be the relative cost of each option.

The exclusive rights to provide power to particular communities and the existing supply contracts with

those communities are additional intangible assets of the TVA and each of the PMAs. Most discussions of the transfer of physical power assets implicitly assume that the intangible asset of the customer base would transfer as well. But a contract to sell a certain amount of power at a certain price can have a clear market value that is separate from the value of the physical assets supplying that power. For nonfederal utilities that can supply those communities from nonfederal sources at a low cost, the value of those supply relationships may exceed the value of the federal government's physical assets. As excess generating capacity increases with the spread of competition in wholesale markets, the value of the federal customer base to private utilities may also grow.

Other intangible assets of federal power agencies, however, may not be subject to transfer. For example, the PMAs have access to low-cost government financing, and the TVA benefits from the implicit federal backing of borrowing and protection against outside competition.

Grouping Power Assets for Transfer

Once the Congress has clearly delineated the power and nonpower functions of federal projects and identified the assets it would like to transfer, it must decide how to group those assets for transfer to new owners. The packaging of assets may affect the combined productivity of the transferred assets and the potential value of those assets to new owners. In general, the government may decide on its own how to package assets, or it may let the market decide which assets it wants. Either way, the Congress may legislate reforms altering the operation of facilities that remain under federal control.

Unilateral Government Selection of Assets for Transfer. The Congress may pursue any of four broad options for combining power assets for transfer to new owners. First, it may transfer the TVA or the PMAs—including the power assets of or rights to the power generated by Reclamation and the Corps—to new owners as integrated units, much as they now exist. Each agency could be transferred to a single owner or a consortium of owners.

Second, the Congress may separately transfer the individual power supply systems that make up each of

the power agencies. A supply system is an integrated system composed of generating facilities and the transmission lines linking those power sources with particular communities. In some cases, it may be possible to identify supply systems with the current rate-setting systems of each agency (see Table 8). That split was the basis for the 1995 authorization to sell the two supply systems of the Alaska Power Administration separately. The government could decide to transfer some projects separately but hold onto others or dispose of them as part of a different grouping. (Breaking up the Tennessee Valley Authority or the Bonneville Power Administration on that basis would be difficult, because each of those agencies has integrated its supply systems into a single rate-setting system.)

Third, the Congress may transfer the individual transmission systems to new owners but retain federal ownership of power-generating facilities. The transfer would probably, but not necessarily, include the rights to market federal power to existing customers—an intangible asset. Such a division may make sense where hydropower projects serve multiple purposes that a public agency could manage more efficiently than a

private firm. It may also make sense for nuclear plants of the TVA that no one would want to purchase. For the Southeastern Power Administration, which already relies completely on investor-owned transmission systems, that option would only entail transferring the rights to market federal power.

Fourth, the Congress may transfer individual power-generating facilities but retain federal responsibilities for transmission and marketing. Retaining some government control may make sense if operating the transmission systems directly was more efficient than relying on existing public service regulations or other policy solutions as a way of guaranteeing low-cost service to small, remote communities.

Letting the Market Decide Which Assets to Transfer. Alternatively, the government may simply offer all the components of its power program and allow new owners to combine assets in any way they want or can afford. Many people assume that new owners would operate federal power facilities much as they are operated today, in which case the particular distribution of assets among new owners would not on its own alter

Table 8.
Number of Rate-Setting Systems and Power Projects Managed by Federal Utilities, Calendar Year 1995

	Tennessee Valley Authority	Power Marketing Administrations				
		Bonne- ville	South- western	South- eastern	Alaska	Western Area
Rate-Setting Systems	1	1	3 ^a	4	2	11 ^b
Operating Power Plants						
Steam plants	12	0	0	0	0	1 ^c
Nuclear plants	5 ^d	1	0	0	0	0
Combustion plants	4	0	0	0	0	0
Hydropower projects	31	25	24	23	3	56

SOURCE: Congressional Budget Office using data from the 1995 annual reports of the Tennessee Valley Authority and the power marketing administrations.

- The Southwestern Power Administration markets about 98 percent of its total sales through a single rate-setting system.
- The 11 rate-setting systems encompass 23 power systems. The Western Area Power Administration markets about 95 percent of its total sales through just five of its rate-setting systems.
- Reflects the Bureau of Reclamation's 24.3 percent share of the coal-fired Navajo Generating Station.
- Includes units at Watts Bar 1 and Browns Ferry 3, which started operating in 1996.

the efficiency of the overall system or the total value of those assets. But some owners may be able to raise the value of particular power assets by integrating them with their own power systems or using those assets in entirely new ways. That is the advantage of allowing the market to decide what to transfer.

For example, hydropower plants that currently supply base-load power may be used as sources of peak power. Similarly, transmission systems that now serve as dedicated lines, connecting individual power plants with specific distributors, may be used as part of a broad system balancing the generating and demand loads of many sites. A nonfederal utility that has excess supply capacity may want to acquire only the rights to service federal customers and would therefore not be interested in purchasing any federal generating facilities or transmission systems.

Some physical assets of the government may be put to entirely new uses. For example, the Bureau of Reclamation, the Corps of Engineers, the Tennessee Valley Authority, and all five power marketing administrations hold dedicated radio frequencies (generally from 1,710 megahertz to 1,850 megahertz).³ The federal agencies operate microwave stations to transmit information about electric power distribution, but they may be holding a broader spectrum of frequencies than needed or be able to monitor some remote sites using land lines. Private interests could use those same frequencies to support wide-area land mobile services (cellular phones)—services that potentially have a greater economic value, as demonstrated by recent spectrum auctions conducted by the Federal Communications Commission. Telecommunication interests would also find the transmission assets of the power agencies valuable; existing power poles and rights of way could be used to string new communication lines.

Allowing businesses or local governments to select (either in advance or through the bidding process) the groupings of federal power assets that they believe will yield the greatest returns may most enhance the productive efficiency of the overall power industry.

What Is the Market Value of Federal Power Assets?

The potential value of assets to new owners may hinge on decisions about which assets to transfer and what restrictions to place on such a transfer. Together with additional information on net budgetary receipts from program operations, an assessment of market values can indicate which particular sales would be most likely to produce budgetary savings. Any restrictions that the government places on the sale of assets may reduce their market value and therefore the savings from privatization.

This study investigates the value of federal power assets to new users under various restrictions on the operation of those assets and the pricing of power. That valuation includes the physical assets supporting power generation and transmission as well as such basic intangibles as the rights to use water flows and to service current customers. (Whether a new owner takes ownership title or a simple right of access to the government's hydropower assets does not matter, because similar restrictions would affect operations either way.)

Market Valuations for an Unrestricted Sale

The highest valuation of federal assets derives from a sale that imposes no special restrictions on the future operation of power facilities or the pricing of power—beyond what is already standard for nonfederal facilities—or on who may bid for federal assets. The assumption of no restrictions also excuses the buyer from any requirements to pay off a power agency's debts or continue financial support for nonpower activities. The Congressional Budget Office's analysis assumes a potential for increased earnings from changes in power rates and productivity under new management. But the market valuations do not reflect any increase in earnings from operating existing assets in new combinations or for new purposes. They also place no value on the additional social gain from selling assets to the highest bidder. Social gain may result if the bidder is the most efficient operator, finds the best use for all facilities, and sells power where it is most in demand.

3. Department of Commerce, National Telecommunications and Information Administration, *Spectrum Reallocation Final Report*, NTIA Special Publication 95-32 (February 1995).

The goal of estimating market value in different ways is to demonstrate the general proximity of achievable valuations, not the differences. In theory, all should yield the same answer. In practice, the answers may diverge because of the lack of cost data and the necessity of relying on assumptions about future costs and revenues.

Valuations Based on Net Cash Flow

Economic theory suggests that the highest price any business would be willing to pay for federal assets should reflect its independent assessment of the present value of the net operating income, or cash flow, that those assets can produce in the future. (Net cash flow is the difference between expected sales revenues and operating costs. Present-value calculations scale down those flows to identify the investment today that would produce the same income stream in the future.)

But there are practical drawbacks to identifying the maximum value of federal assets. Uncertainty about which business will be submitting the highest bid or what its particular cash flow assumptions will be requires the consideration of a likely range of market values rather than a point estimate. And the availability of data on cash flows for specific lines of business restricts the analysis to the valuation of power assets in total and transmission assets alone. (See Appendix B for a description of the major elements of net cash flow for each of the federal power programs, the calculation of present values, and the results of a sensitivity analysis showing how those values change with the major assumptions.)

Cash Flow Assumptions and the Treatment of Market Uncertainty. Significant uncertainty can underlie net cash flow valuations, because the potential bidders for federal assets—whether they are investor-owned utilities, cooperatives, independent power producers, or public entities—will probably not share the same assessments of future power rates or operating costs. Also, their exposure to federal and local taxes will differ: private utilities benefit in varying degrees from using investment tax credits and deferring taxes, cooperatives are exempt from federal taxes on business income, and publicly owned utilities are exempt from all income taxes. Moreover, utilities use different discount rates to scale down future cash flows. The discount

rate the agencies use reflects the returns available to them from other investment opportunities, their debt structure, and their independent assessment of project risk.

Identifying a likely range for market bids, however, does not require investigating all combinations of possible values for revenues, operating costs, taxes, and discount rates. The combinations of assumed values that would produce extreme market valuations generally represent very unlikely occurrences. The range of possible values for some variables is not particularly wide, and variations in some values would have only a small impact on market valuations.

This study focuses on the uncertainty surrounding charges for wholesale power rates (for bids on all power assets) and charges for transmission services (for bids on transmission systems only). Uncertainty about those values—caused largely by the restructuring of wholesale and retail power markets that is now under way—underlies the market valuation regardless of who the bidder is.

Valuing Total Power Assets with Constant and Rising Power Rates. The bidder who establishes the maximum value for total federal assets is assumed to be a tax-paying entity who discounts future earnings at 10 percent (representing the weighted average cost of capital for investor-owned utilities) and totals the annual net cash flows over a 30-year period (representing the remaining life of power assets). That bidder pays a marginal rate on combined federal and local taxes of 40 percent. And after-tax income reflects depreciation charges based on the plant value established by the sale price. Beyond those profitability and tax-liability requirements, the bidder assumes that the 1995 net income of each federal program will be representative of future nominal earnings, with three adjustments:

- o For the TVA, the cash flow analysis is based on net operating income for 1996 to reflect changes in capital spending, operating costs, and sales when two nuclear projects were completed.
- o New owners will initially raise power rates consistent with the difference between what local investor-owned utilities and federal agencies currently charge publicly owned utilities and cooperatives for wholesale power (see Table 9). Local and

Table 9.
Comparison of Average Revenues from Power Operations for Federal and Investor-Owned Utilities,
Fiscal Year 1995 (In cents per kilowatt-hour)

Customers	Federal Utilities						Investor-Owned Utilities
	Tennessee Valley Authority	Bonneville	South-western	South-eastern	Alaska	Western Area ^a	
Southeastern Electric Reliability Council (SERC)							
Public Utilities and Cooperatives ^b	4.2	*	*	2.8	*	*	4.7 ^c
Investor-Owned Utilities	n.s.	*	*	n.s.	*	*	4.7 ^c
Industrial Establishments	2.8	*	*	n.s.	*	*	4.4
Southwest Power Pool (SPP)							
Public Utilities and Cooperatives ^b	*	*	1.3	*	*	*	3.2 ^c
Investor-Owned Utilities	*	*	n.s.	*	*	*	2.4
Industrial Establishments	*	*	n.s.	*	*	*	4.1
Western Systems Coordinating Council (WSCC)							
Public Utilities and Cooperatives ^b	*	2.6	*	*	*	2.0	3.9 ^c
Investor-Owned Utilities	*	3.9	*	*	*	1.6	2.8
Industrial Establishments	*	2.6	*	*	*	n.s.	5.5
Alaskan System Coordination Council (ASCC)							
Public Utilities and Cooperatives ^b	*	*	*	*	1.6	*	n.s.
Investor-Owned Utilities	*	*	*	*	3.2	*	n.s.
Industrial Establishments	*	*	*	*	n.s.	*	7.8

SOURCE: Congressional Budget Office using data from the 1995 annual reports of the Tennessee Valley Authority and the power marketing administrations. For investor-owned utilities, CBO used data from Energy Information Administration Forms EIA-861 and FERC-1 for calendar year 1995.

NOTES: Data for federal utilities consist of sales directly to industrial establishments; data for investor-owned utilities are sales to the industrial sector. Regional data for investor-owned utilities (regardless of the utility's location) reflect sales into census divisions—South Atlantic and East South Central for SERC, West South Central for SPP, Pacific Contiguous and Mountain for WSCC—and the state of Alaska for ASCC. SERC, SPP, WSCC, and ASCC are the North American Electric Reliability Council regions.

* = not applicable; n.s. = no sales.

- a. A small volume of sales by the Western Area Power Administration takes place in the Mid-Continent Area Power Pool.
- b. Public utilities include municipal and state utilities as well as public utility and irrigation districts.
- c. Data are preliminary.

federal regulatory agencies do not restrict those rate changes.

- o New owners of PMA hydropower facilities will be able to increase output by 5 percent at no additional cost. New owners of TVA facilities will increase output to use all existing generating capacity.

The assumed increase in productivity of 5 percent for the PMAs is illustrative. It conservatively represents only a small fraction of the difference between average productive efficiencies for federal and nonfederal hydropower plants. For the TVA, the assumed increase in output (and an associated rise in operating costs) is based on generating capacity that the TVA

system has recently added by activating its Browns Ferry 3 and Watts Bar 1 nuclear units. Such an adjustment is necessary to make the future cash flow for the private sector's valuation consistent with the TVA's current supply capabilities and outlook for growth in regional demand.

Alternative assumptions about future growth in net cash flow establish a range for the potential market values. CBO assumes that net cash flow in subsequent years will be either constant in nominal dollars (for a low market value) or will rise with inflation (for a high market value). The low market-value estimates are consistent with a more basic assumption that growing competition in wholesale markets will limit rate increases for the next few years. (In both cases, unit operating costs are implicitly assumed to grow at the same pace as power rates.) Demonstrating the influence of that competition, the national average for retail power rates for all classes of customers has been virtually constant in nominal terms for the past five years.⁴ The case of a high market value is generally consistent with long-term projections of electricity rates by the Energy Information Administration. For retail rates, the EIA projects an average annual growth of nearly 3 percent in nominal dollars, consistent with the trend of the past decade.⁵

An assumption of constant cash flow in nominal terms yields an estimate of total market value of more than \$45 billion (see Table 10). The alternative assumption that power rates and operating costs grow with inflation yields an estimate of total market value of \$62 billion.

In both cases, market values for the Tennessee Valley Authority and the Bonneville Power Administration dominate the totals. For example, the high estimate of \$62 billion includes values of more than \$30 billion for the TVA and about \$20 billion for the BPA. (Although the TVA markets about 65 percent more power than the BPA, the low generating costs for hydropower greatly

enhance the BPA's market value compared with that of the TVA.) The total value for the assets of the Western Area Power Administration in that case is more than \$8 billion. And the three smallest power marketing administrations—the Southwestern, Southeastern, and Alaska PMAs—together would be worth about \$3 billion.

Rating Transmission Assets with Low and High Transmission Charges. In general, current data do not permit a cash flow analysis for each type of facility that the government may want to sell separately—in particular, generating and transmission assets. The reason is that electric utilities as well as federal power agencies have operated as vertically integrated units and do not report revenues and costs separately for different generating plants and transmission systems. That is changing with competition, however, and most private utilities are establishing their generating and transmission activities as distinct profit centers.

Despite the lack of data on costs and revenues from federal transmission activities, it is possible to illustrate the potential market value of federal transmission assets by assuming that net cash flow from those services will average between 1 cent and 2 cents per kilowatt-hour.⁶ Given current sales levels for federal agencies, including likely sales growth for the TVA now that its nuclear program is completed, the present value of transmission assets may be between \$2 billion and \$5 billion. Those figures reflect estimates of variable transmission costs. They do not incorporate the economic value of transmission systems for guaranteeing an outlet for generating capacity and may thus understate the full market value of federal transmission assets.

4. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(97/01) (January 1997), Table 9.9.

5. Energy Information Administration, *Annual Energy Outlook 1997*, DOE/EIA-0383(97) (December 1996). In the reference case projected through 2015, average retail rates fall by 0.6 percent annually in constant dollars, and the consumer price index grows at 3.5 percent.

6. As a basis for comparison, the Federal Energy Regulatory Commission assumed a range of 1 cent to 3 cents per kWh for transmission charges in the base case of its report, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities (RM95-8-000) and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (RM94-7-001): Final Environment Impact Statement*, FERC/EIS-0096 (April 1996). Equating transmission charges with net cash flow from transmission, as this study does, is equivalent to assuming that variable costs of transmission (operating costs and taxes) are negligible on a per-kilowatt-hour basis. Also, the Bonneville Power Administration recently established a charge of 1.4 cents per kWh to utilities for the use of its transmission lines (or \$12.01 per kilowatt-year divided by 8,760 hours).

Table 10.
Potential Market Valuations of Federal Power Assets (In billions of dollars)

	Tennessee Valley Authority	Power Marketing Administrations					
Power Assets		Bonne- ville	South- western	South- eastern	Alaska	Western Area	Total
Net Cash Flow Valuation ^a							
All Power Assets, Assuming ^b							
Low market value ^c	22.4	14.6	1.3	1.0	0.1	6.1	45.5
High market value ^d	30.5	19.9	1.7	1.4	0.1	8.3	62.0
Transmission System Assets, Assuming							
Transmission Rates Equal							
1 cent per kilowatt-hour	1.4	0.8	0.1	0	e	0.3	2.6
2 cents per kilowatt-hour	2.8	1.6	0.2	0	e	0.7	5.3
Replacement-Cost Valuation							
Steam Plants	5.9	*	*	*	*	0.2	6.1
Nuclear Plants	9.1	1.8	*	*	*	*	10.9
Combustion Plants	0.5	*	*	*	*	*	0.5
Hydropower Projects	0.9	5.7	0.6	0.9	e	2.6	10.7
Transmission Systems	3.7	3.2	0.3	0	e	3.8	11.0
General Plant (Buildings)	<u>1.0</u>	<u>0.2</u>	<u>e</u>	<u>e</u>	<u>e</u>	<u>0.1</u>	<u>1.3</u>
Total	21.1	10.9	0.9	0.9	0.1	6.7	40.4
Financial-Ratio Valuation ^f							
All Power Assets	29.3	11.5	0.5	0.8	0.1	3.6	45.8

SOURCE: Congressional Budget Office using data from the 1996 annual report of the Tennessee Valley Authority (TVA), the 1995 annual reports of the power marketing administrations (PMAs), and the Energy Information Administration.

NOTE: * = not applicable.

- a. Net present-value calculation, based on 30 years of sales, discounted at 10 percent. Market valuations also reflect a 40 percent marginal rate of taxation (including federal and state income taxes and nonincome taxes) and straight-line depreciation of the plant's acquisition cost for 30 years.
- b. Net cash flow excludes tax-equivalent payments of the Tennessee Valley Authority (\$256 million) and operating costs for residential exchange (\$198 million) and environmental and fish and wildlife programs (\$71 million) of the Bonneville Power Administration.
- c. The values assume that first-year power rates equal the regional average power rates of investor-owned utilities and that nominal rates and operating costs are constant thereafter (that is, nominal net cash flow remains constant). Values for the PMAs assume a 5 percent increase in power sales over 1995 levels. The value for the TVA assumes that sales reflect the power from two nuclear projects completed in 1996.
- d. The values assume that first-year power rates equal the regional average power rates of investor-owned utilities and that nominal rates and operating costs grow with inflation (3 percent annually) thereafter. Values for the PMAs assume a 5 percent increase in power sales over 1995 levels. The value for the TVA assumes that sales reflect the power from two nuclear projects completed in 1996.
- e. Less than \$25 million.
- f. Based on the ratio of plant value to sales revenue.

Valuations Based on Replacement Cost

Information on the current costs that nonfederal utilities pay for power equipment provides an alternative basis for estimating the market value of federal assets. The rationale for that methodology is straightforward. A business would not pay more on a unit-of-capacity basis to acquire federal power assets than it would for similar equipment from any other source—if it expects to charge the same rates and incur the same operating costs for that new power as it would for power from other sources.

One way of estimating replacement costs is to divide the book value of a nonfederal utility plant by its capacity. The result is the cost per unit of capacity. The value of federal assets would then reflect the product of those unit costs and the respective capacities of federal facilities. That approach has several advantages. It is expedient, because the Department of Energy reports information on plant values and capacity for investor-owned and public utilities.⁷ Moreover, the available data support the estimation of replacement costs for different types of federal facilities, which may be useful if the government decides to sell its power assets piecemeal. This analysis looks at book values for the generating plant (steam, nuclear, combustion, and hydropower), the transmission system, and the general plant (associated land and buildings). Capacity is represented by megawatts of manufacturer's specified capacity for generating, circuit-miles for transmission, and number of utility employees for general plant.

Replacement costs based on book values for nonfederal plants can give a more up-to-date view of market value than would the original construction costs for federal plants. Federal expenditures for the nation's large hydropower facilities, in particular, were made many decades ago and thus do not reflect the increases in construction costs that would be a part of the book values for newer, nonfederal facilities. Book values for nonfederal plants may also be updated to reflect sales

of existing facilities (although CBO does not have information on the extent of such resale activity).

However, current market values reflect current outlooks for future profitability, which do not show up in book values. In general, replacement costs based on book values tend to overstate market values when operating costs are rising or power rates are falling. For example, widespread experience with operating difficulties and high operating costs for nuclear power plants has greatly diminished their market value in relation to the original construction costs. (The general lack of resale activity for nuclear plants means their book values have not adjusted to market conditions.) Moreover, downward pressure on wholesale power rates—a consequence of growing competition from nonutilities—is lowering market values for utilities' generating plants across the country.

By contrast, replacement costs for transmission assets suggest a higher market value than that which the assessments of cash flow provide. Transmission assets may have value beyond those that direct transmission charges imply—especially in terms of customer access. As a result, book values for those assets, which reflect a steady pace of new construction and replacement over time, may provide a more accurate assessment of market value than would a valuation of net cash flow based on current transmission charges. The market in wholesale transmission is only now emerging, and it is hard to know how transmission charges will behave in a fully competitive environment.

On the basis of reported plant values and capacities for nonfederal utilities in 1995, the total value of federal assets today may be more than \$40 billion. That figure includes the value of the two TVA nuclear projects that returned to service in 1996. Total generating capacity (for steam, nuclear, combustion, and hydropower plants) accounts for more than \$28 billion of that figure; transmission capacity accounts for \$11 billion; and general plant (including land and buildings) about \$1 billion.

Other Methods of Estimating Market Value

There are other, more expedient methods of estimating market value, primarily involving extrapolation from

7. For plant value, see Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities*, DOE/EIA-0437(95)/1 (December 1996), and *Financial Statistics of Major U.S. Publicly Owned Electric Utilities*, DOE/EIA-0437(95)/2 (July 1997). For generating capacity of utilities, see Energy Information Administration, *Electric Power Annual*, vol. 1, DOE/EIA-0348(95)/1 (July 1996).

aggregate financial statistics for private utilities. For example, a ratio for investor-owned utilities such as plant value to sales revenues can be multiplied by federal revenues to estimate the market value of assets. Because private utilities, unlike federal agencies, are very active in retail sales, it is necessary to scale down those nonfederal revenues to reflect the difference between retail and wholesale power rates. (Average retail rates on final sales to all sectors are nearly double those that utilities charge other utilities.)

Reliance on simple methods, however, can be misleading. For example, with the exception of the TVA, federal power revenues reflect rates to local utilities that are generally lower than rates on utility sales for resale nationwide. Nonfederal plant values include investments in local distribution systems that federal agencies do not have. And, again with the exception of the TVA, nonfederal plant values reflect the large contribution of coal and nuclear energy to the national power mix. Operating costs for hydropower—the main source for PMA sales—are much lower than those for coal and nuclear power plants, which enhances the unit cash flow and, hence, the market value for PMA assets compared with that for other utilities.

Thus, for the power marketing administrations, there are several reasons for believing that estimates of market value based on an extrapolation of simple financial ratios are too low. For the TVA, however, which operates a mix of coal, nuclear, gas, and hydropower that is similar to the average mix for nonfederal utilities, a simple approach may provide useful information. Data on the ratio of utility plant value to revenues indicate a market value for the TVA of about \$29 billion—close to the high end of the valuations based on net cash flow for that agency.

How Would Constraints on an Asset Sale Affect Market Value?

The largest amount that the public can receive from a sale of federal power assets is the market value of those assets to the highest bidder in an open competition. The Congress could circumscribe a sale in at least three ways that would reduce public receipts in relation to

those that the highest bidder could offer. The Congress may:

- o Impose a limit on the sales price;
- o Impose restrictions on future operations that have the effect of lowering the market value to the highest bidder; or
- o Restrict the competition for federal assets, thereby defining the qualifications of the highest bidder.

Limits on the Sales Price

Some would-be purchasers of federal power assets have proposed that the government should sell power assets to them at a sales price that reflects only the value of the outstanding federal debt of the power agencies or perhaps only the government's historical investment in power projects.⁸ (Outstanding debt plus any amount of debt repaid would equal the historical investment.) Those equity arguments seek to transfer the benefits of historically low costs to particular groups. From the perspective of economic efficiency, however, obligations incurred from past financing decisions and cumulative capital expenditures represent sunk costs and have no role in establishing the current value of assets. Today's value depends only on the outlook for future income.

Repaying the Face Value of Outstanding Debts.

Some proponents of a debt-based price argue that they have already paid for part of the original costs of constructing power facilities through the depreciation component of their power rates. On that basis, there are proposals to compensate the federal government only for the outstanding debt of the power agencies—either the face value of the debt or the present value of future payments and interest on the debt. To simplify the analysis, this section looks only at sale prices based on the face value of debt.

At the end of fiscal year 1995, the face value of the outstanding debt of the federal power agencies—in-

8. For example, see testimony by Glenn English of the National Rural Electric Cooperative Association (NRECA) before the Subcommittee on Water and Power Resources, House Committee on Resources, May 18, 1995. In that testimony, the NRECA opposed the sale of federal power assets.

cluding past appropriations for power programs remaining to be repaid through power revenues, plus outstanding debt with the Federal Financing Bank and the general public—totaled \$48.3 billion (see Table 11). Public debt, amounting to more than \$30 billion, consisted primarily of TVA bond issues, repayment obligations of the BPA for debts of the Washington Public Power Supply System, and nonfederal financing of WAPA upgrades to Hoover Dam.

The outstanding debt for the federal power agencies depends on original costs, the share of the total costs allocated to power, and the debt's repayment history. The total and allocated costs can be somewhat arbitrary. They depend on allocation decisions by Recla-

mation and the Corps—which follow no consistent formula—and legislative direction. For example, the government's full investment in the Richard B. Russell project of the Southeastern Power Administration will not become part of the SEPA's capital debt until or unless that project enters service. Similarly, the debt obligations of the Alaska Power Administration—the basis for the sale price for that agency—were lowered to exclude costs for completing certain construction work. A schedule for repayment, which depends on the project life for each individual facility, can also be arbitrary. For example, the Southwestern Power Administration has recorded a project life for some assets that is over 90 years. On that basis, little repayment occurs from year to year.

Table 11.
Alternative Bases for Sales Price and Related Losses in Public Receipts Compared with Sales at High and Low Market Values (In billions of dollars)

	Tennessee Valley Authority	Power Marketing Administrations					Total ^a
		Bonne- ville	South- western	South- eastern	Alaska	Western Area	
Outstanding Debt of Power Agencies ^b	27.3	16.5	0.6	1.0	0.2	2.6	48.3
Loss in receipts compared with sale at							
Low market value	n.s.	n.s.	0.6	0.1	n.s.	3.5	4.2
High market value	3.2	3.4	1.1	0.4	n.s.	5.7	13.8
Total Investment in Power Assets (Exclud- ing inactive generating projects) ^c	28.3	14.4	1.1	1.5	0.2	5.6	51.1
Loss in receipts compared with sale at							
Low market value	n.s.	0.3	0.1	n.s.	n.s.	0.4	0.8
High market value	2.2	5.6	0.6	n.s.	n.s.	2.7	11.0
Marketing Valuations with Open Sale to Highest Bidder							
Low market value	22.4	14.6	1.3	1.0	0.1	6.1	45.5
High market value	30.5	19.9	1.7	1.4	0.1	8.3	62.0

SOURCE: Congressional Budget Office.

NOTE: n.s. = no sale, since market value to highest bidder would be below the price based on debt or historical investment.

- a. Excludes "no sale" entries, for which debt or historical investment would have exceeded market value.
- b. Reflects the sum of outstanding appropriated debt, debt held by the Federal Financing Bank, and publicly held debt—including the current portion—at the end of 1995. For the Western Area Power Administration, the figure includes \$167 million in nonfederal investments to be repaid.
- c. Total investment is through 1995. Excludes deferred nuclear projects of the Tennessee Valley Authority (units at Watts Bar 2 and Bellefonte 1 and 2, for which no completion plans exist), canceled nuclear projects of the Bonneville Power Administration (investments of the Washington Public Power Supply System for which the BPA has incurred debt repayment obligations), and work in progress on the Southeastern Power Administration's Russell Dam project.

Furthermore, the debt basis for a sales price may not include all the financial liabilities of the power agencies. For example, all of the power agencies have entered various net-billing agreements as a way of financing construction work by nonfederal entities, and the long-term billing concessions implicit in those agreements represent financial liabilities. A focus on outstanding debts for the TVA and BPA would omit the government's additional liabilities for the decommissioning of nuclear plants.

The outstanding debts of the TVA and BPA exceed their estimated market values in the case of a low market value. Purchasers would not want to acquire the assets of those agencies at those prices. In the case of a high market value, the market value exceeds outstanding debts by \$3.2 billion for the TVA and by \$3.4 billion for the BPA. Much of the TVA and BPA public debts were incurred to finance expensive nuclear projects. New owners may not be interested, however, in acquiring the government's nuclear facilities because their operating costs are high. Moreover, they would be liable in the future for the uncertain costs of nuclear cleanup.

Understandably, arguments for basing the sales price on outstanding debts are made most frequently in connection with the assets of the SWPA, the SEPA, and the WAPA. Limiting the sales price in that way for those three programs would reduce public receipts from their sale by between \$4 billion and \$7 billion compared with the potential amounts that could be obtained in an open competition.

Repaying Historical Construction Costs. Other proponents of establishing a sales price below full market value argue that the federal government should not sell facilities for more than it paid for them. That argument, too, ignores any inflation of original construction costs. On a historical basis, the federal government has spent about \$52 billion constructing its power program. That figure does not count nearly \$11 billion in expenditures on inactive nuclear projects of the TVA and the BPA or \$0.4 billion in expenditures on the troubled Richard B. Russell hydropower project of the SEPA.

Historical costs for individual projects are far below the market value of the facilities—especially for the large hydropower plants built in the 1930s and 1940s. For example, the original construction cost for the Hoo-

ver Dam was only about \$100 million. Adjusting for inflation since 1936, the cost of building that facility today would be well over \$1 billion. A sale at historical cost could generate significant market interest under the assumptions of a high market value, but in relation to what the market would pay, the government would lose \$11 billion from such sales (see Table 11).

Even in the case of a low market value, the earning potential of many federal projects does not live up to the historical investment in operating facilities, for several reasons. The market value of some projects is low compared with the government's full investment because of those projects' high operating costs or, equivalently, low productivity. For other projects, current replacement values are lower than original construction costs because engineering designs and construction techniques have improved. Including expenditures on incomplete facilities would further inflate estimates of historical costs in relation to market values.

Limits on Future Power Operations That Affect Market Value

The Congress may also influence the direct public receipts from a competitive sale of power assets by imposing restrictions on a new owner's operations that will reduce future net cash flow. Of particular interest may be the continuation of cash support for some nonpower activities and limitations on future increases in power rates. Congressional action on current requirements for FERC licensing of nonfederal hydropower projects may also affect future cash flows.

Continuing Direct Support for Certain Nonpower Activities. Federal power revenues currently provide direct support for a number of nonpower activities because the costs of those activities are a part of the power rate base (see Tables B-1 and B-2). One such activity would be the payments in lieu of taxes (PILT) that the TVA makes to local governments. A new owner of the TVA's assets would pay local taxes, but the communities that receive those payments may differ from the communities that now receive the PILT. Other nonpower activities would include the BPA's residential exchange program (a subsidy to investor-owned utilities in the Northwest), funding of new construction and operation of fish and wildlife projects.

The present value to a taxpaying entity of future payments to support the TVA's PILT and the BPA's residential exchange and fish and wildlife programs at their 1995 funding levels would total about \$4 billion (see Table 12). Any requirement for a new owner to continue supporting such activities would reduce the market value and therefore decrease by that amount the public receipts from a competitive sale of power assets.

Limiting Increases in Power Rates. Any requirement that the new owner of a federal power asset not raise power rates from current levels would result in a loss of sales revenues. That loss would reduce the market value and potential public receipts from a sale.

It is difficult to know how much a new owner might want to raise power rates. For 1995, the data on wholesale trade in electric power indicate that the TVA already charges its customers close to what nearby investor-owned utilities charge theirs (see Table 9). Power rates of the PMAs appear to be below the regional rates of investor-owned utilities, but the growth of competition in wholesale markets may narrow the gap in the future.

Rather than guess at how much rates might rise, CBO estimates the loss in public receipts on the basis of restrictions that would keep new owners from raising power rates for investor-owned utilities to current lev-

Table 12.
Potential Restrictions on Plant Operations and Related Losses in Public Receipts
(In billions of current dollars)

Cause of Loss	Tennessee Valley Authority	Power Marketing Administrations					Total
		Bonne- ville	South- western	South- eastern	Alaska	Western Area	
Requirement to Continue Support for Certain Nonpower Activities at 1995 Levels ^a							
Payments in lieu of taxes	1.8	*	*	*	*	*	1.8
Residential exchange program and support for fish and wildlife program	*	2.1	*	*	*	*	2.1
Requirement to Freeze Power Rates at Current Levels for Five Years at							
Low market value	2.7	3.4	0.4	0.3	b	2.0	8.8
High market value	2.8	3.6	0.4	0.3	b	2.2	9.3
Delay in Start-up of Hydropower Operations for Five Years at							
Low market value	1.3	5.3	0.5	0.4	b	2.2	9.7
High market value	1.4	5.6	0.5	0.4	b	2.3	10.2

SOURCE: Congressional Budget Office.

NOTE: * = not applicable.

a. Present-value calculation, based on 30 years of tax-equivalent payments of the Tennessee Valley Authority (\$256 million) and operating costs for residential exchange (\$198 million) and environmental and fish and wildlife programs (\$71 million) of the Bonneville Power Administration. Payments have been discounted at 10 percent. Market valuations reflect a 40 percent marginal rate of taxation (including federal and state income taxes and nonincome taxes) and straight-line depreciation of the plant's acquisition cost for 30 years.

b. Less than \$50 million.

els. CBO has made the comparison with private utilities in the same regional market—as represented by North American Electric Reliability Council regions—for rate freezes lasting, for instance, five years. The present value of lost sales revenues to taxpaying entities as a result of the inability to raise rates to current market levels for five years would reduce the total market value of federal power assets by around \$8 billion (see Table 12).

Delaying the Start-up of Power Operations. Any government actions that postpone the date when a new owner can start earning income from federal power assets or that make that future income less certain diminish the market value of those assets today.⁹ One potential source of delay and uncertainty may stem from requirements for the FERC to license nonfederal dams. Another is related to the legislative and administrative process for structuring a sale. Delays in transfers would not affect the ultimate sales price in nominal dollars—assuming no additional lag between payment and start-up—but would reduce the value of such a sale in today's dollars.

The FERC's licensing of nonfederal dams establishes conditions under which a hydropower project must operate to satisfy a multitude of legal and policy stipulations. Specific limits on the FERC's flexibility in issuing licenses stem from the authority of other federal and state agencies to attach mandatory conditions to those licenses. In some cases, the licensing process could alter the management of water flows for formerly federal dams, thereby affecting their power-generating capacities and market values. In others, such licenses could also impose new costs of operation or ownership. A five-year delay from purchase date to start-up, for instance, would reduce the total market value of federal hydropower assets by around \$10 billion. (That figure does not assume any alternative earnings potential for transmission assets idled by such delays.)

The licensing process and the accompanying loss of value are not unavoidable results of privatization. For example, the Congress could amend the Federal Power Act and authorize the FERC to issue temporary licenses to new owners of federal dams—grandfathering them

into the licensing requirement and the enforcement of other applicable laws. In the case of the Alaska Power Administration, the legislation authorizing the transfer of APA assets explicitly exempts the new owners from the licensing requirement. (That exemption remains in force as long as ownership of the dams does not change.) Environmental concerns about management of the dams were addressed in an agreement that the Fish and Wildlife Service negotiated with the new owners before the authorizing bill was passed.

Delays in the transfer of title or control over federal power assets would not affect the amount that businesses would be willing to pay for those assets at the time of transfer. Some period of delay is likely—the Congress debated authorization of the sale of the Alaska Power Administration for seven years, and the transfer is still not complete. But without any changes in assumptions about cash flow in the interim, the cash amount that businesses would bid for the control of federal assets in the future would generally match the cash amount they would pay to take control today. From the perspective of the federal government, today's value of that delayed payment would be smaller than the nominal payment by about 7 percent for each year of delay. (Seven percent reflects the government's opportunity cost of capital or the discount rate.) This study does not assess the possibility of new requirements for operating or capital costs that may become evident with the passage of time. A need for expensive, emergency repairs to submarine cables of the Alaska Power Administration, for example, became apparent after the legislation authorizing the sale was passed.

Restrictions on Who Can Buy Federal Assets

If the Congress limited the sales price to anything below a market-clearing price, it would also have to restrict the list of buyers. This study does not evaluate additional restrictions on who can purchase power assets. Under some proposals, the current customers for federal power—generally, publicly owned utilities and cooperatives—would be the only allowable purchasers, as was the case in the sale of assets of the Alaska Power Administration. Under others, the current customers would have the right of first refusal.

9. For a discussion of the FERC's licensing requirements and other practical concerns that the Congress may need to address, see General Accounting Office, *Federal Power: Issues Related to the Divestiture of Federal Hydropower Resources*, GAO/RCED-97-48 (March 1997).

Many proposals to sell federal assets to current customers mention a sales price based on outstanding debts or historical costs. In those cases, estimates of sales proceeds would be consistent with the estimates in Table 11. But a valuation of net cash flow for a sale restricted to public entities or tax-exempt organizations differs from that for a sale to the highest bidder. In particular, changes in assumptions about tax rates and discount rates would be necessary. Assumptions about discount rates would depend on whether the income from the bonds that such entities issue to finance the purchase were tax-exempt. (Public bonds that support the acquisition of commercial enterprises—as opposed to the construction of new facilities—are generally not exempt from federal taxes. The Congress passed legislation in 1996 that would grant such an exemption to the state of Alaska for financing its purchase of APA assets.)

How to Conduct a Sale to Achieve Maximum Value

Even for a competitive sale of power assets, the government may not receive the full market value for those assets if one bidder has special information about the market that is not available to the competition. The concept of "open competition" requires that no bidder have informational advantages. If such advantages exist, however, the government has strategies for countering them.

For example, the government can require prospective bidders to submit information about their plans to use government facilities. It can use that information to identify assets for which a market interest exists, establish minimum acceptable bids for those assets, accept sealed bids, and award the sale to the bidder who offers the highest amount above the minimum. In the past, the Minerals Management Service has followed that process in its sale of offshore leases for oil and gas production, assembling exploration data from oil companies to help it establish the potential value of resources. If there are concerns that revenues from such bidding will not match the full market value of the asset—perhaps because of constraints on the competition from incomplete information or high capital costs—the gov-

ernment may also establish a royalty or special tax on subsequent profits.

Moreover, the government may encourage wide competition for individual assets and simultaneously avoid the prospect of lost system efficiency caused by coordination problems among new owners if it auctions operator and ownership rights separately. The Department of Energy recently described that approach in its plans to sell the naval petroleum reserve at Elk Hills.

Under circumstances in which information about the value of assets is not readily available, alternative sale procedures may raise more revenues, make sure assets are put to better social uses, and promote more competition than an outright sale to the highest bidder with a minimum bid threshold. The government has recently used an open auction of assets in stages that allow each bidder to react to the market information revealed in the bidding strategies of other parties. A multiple-round auction of power assets may promote economic efficiency as well as increase federal revenues from the sale. The Federal Communications Commission conducted that type of auction in selling licenses for the use of portions of the radio spectrum.¹⁰ There are strong similarities between the sale of spectrum licenses and power facilities: many different combinations of asset types and locations may be offered, each having a different value for different buyers. It is difficult to know in advance which combinations will be of greatest value.

The government can also sell assets in stages—for example, by initially selling only a controlling interest in federal facilities and holding on to the remaining interest until the true market value of the asset becomes clear. The British government has taken that approach in privatizing electric utilities and other industries; the government sells common stock in the enterprise to the general public but initially maintains a share of that stock.¹¹

10. An analysis of the government's spectrum auctions appears in John McMillan, "Selling Spectrum Rights," *Journal of Economic Perspectives*, vol. 8, no. 3 (Summer 1994). The Congressional Budget Office has estimated the value of spectrum rights in two studies: *Auctioning Radio Spectrum Licenses* (March 1992), and *Where Do We Go From Here? The FCC Auctions and the Future of Radio Spectrum Management* (April 1997).

11. See John Vickers and George Yarrow, "The British Electricity Experiment," *Economic Policy*, vol. 12 (1991).

Budgetary Consequences of Selling Power Assets

The prospect of using the proceeds from sales of federal power assets to help control the nation's budget has encouraged proposals to privatize all or parts of the program. But the sale of a revenue-producing asset—even one that may operate more efficiently with new ownership—might not yield budgetary savings over the long term. Selling such assets is tantamount to trading the future income that those assets could produce for a lump-sum payment today. The future income from the government's power program would equal the difference between program receipts (from power sales) and outlays (for operation and construction). A sale of federal assets produces long-term budgetary savings only if the sale price exceeds the present value of the income that the government gives up, less any increase in federal tax receipts after the sale.¹ Estimates of budgetary savings may say little about gains in efficiency from privatization, because market values reflect tax liabilities and costs of capital that are not part of the budgetary impact.

Nonetheless, selling many of the government's power assets—including the power-related facilities of the Bureau of Reclamation and the Corps of Engineers—would yield long-term budgetary savings (on a present-value basis) under certain assumptions about market value. (This chapter does not consider the Alaska Power Administration, which is now in transi-

tion to new ownership.) The budgetary savings from selling all power assets could be worth more than \$16 billion in current dollars, assuming that the sales prices for all assets reflect assumptions of a high market value (\$62 billion).

If one assumes the sales prices of the low-market-value case (\$45 billion for all federal assets), auctioning the Tennessee Valley Authority's assets to the highest bidder would yield budgetary costs, not savings. Budgetary savings would still result from selling the power marketing administrations' assets in that case, but the budgetary cost of selling TVA assets would slightly exceed the combined savings from selling the PMA assets. Selling all the federal power assets under those circumstances would yield a net budgetary cost of \$0.2 billion in present-value terms—close to being deficit neutral.

In both the high- and low-value cases, the Congressional Budget Office assumed that the sale of power assets would not affect the federal obligation for repaying public bonds issued by the TVA or secured by the Bonneville Power Administration.

If CBO's estimates of net budgetary income from future program operations could not be realized, the value of selling power assets for budgetary reasons would be enhanced. Realizing those projections should not be difficult for the smaller PMAs because they have so much latitude to raise power rates. For the TVA and the BPA, however, challenges to the income projections may come from new competitive limits on federal

1. Current dollars of income have greater value to the government than future dollars for two reasons: they can yield additional income in the future by enabling the government to reduce its borrowing (or increase its investment spending), and their purchasing power has not yet been eroded by inflation.

power rates, difficulties in expanding federal sales, or internal cost pressures.

For all the power agencies, three additional considerations could enhance a sale's prospects for budgetary savings. First, future subsidies not included here—such

as appropriations for unprofitable new projects or forgiveness of the power agencies' debts—are possible. Second, additional third-party financing for the construction, maintenance, or operation of power facilities could be used in the future. In effect, the power agencies can obligate the federal government, in the absence

Box 3.

Current Budgetary Treatment of Asset Sales

The Congressional Budget Office (CBO) estimates the budgetary cost of virtually every bill reported by Congressional committees. It does so to show how those legislative proposals would affect spending or revenues. The estimates measure changes in budget authority, outlays, and receipts in relation to projections under current law. Federal law and Congressional rules shape CBO's methodology for preparing legislative cost estimates. The Joint Committee on Taxation (JCT) is responsible for estimating most changes in tax revenues, and CBO includes any JCT estimates in its official cost assessments.

For purposes of the Congressional Budget and Impoundment Control Act of 1974 (the Budget Act) and the Balanced Budget and Emergency Deficit Control Act of 1985 (the Deficit Control Act), CBO assesses the budgetary impact of legislation over a period of five to 10 years. Consistent with federal budgetary accounting, CBO's estimates generally record changes in receipts and outlays on a cash basis and do not discount for the time value of money. Because of the limits on the period of assessment and the focus on changes in annual cash flows, CBO's cost estimates may not reflect the full effect of legislation. That is especially true for a transaction such as an asset sale that results in a large increase in receipts in the near term and small reductions in annual receipts over a period extending far into the future.

The Budget Act and the Deficit Control Act also require CBO to assess the effects of proposed legislation on mandatory spending and receipts separately from the potential impact on future discretionary spending. New legislation that would affect spending on mandatory programs (programs governed by permanent law) is limited by the annual Congressional budget resolution and the pay-as-you-go process of the Deficit Control Act, which was designed to control spending over time. Spending on discretionary programs is determined by annual appropriation bills, which are limited by the spending levels established in the budget resolution. The Deficit Control Act also establishes caps on total appropriations for future years—currently through 2002. Under the two acts, anticipated reductions in future discretionary appropriations cannot be used to offset increases in spending that are recorded on the mandatory side of the budget.

A sale of federal power assets would affect both mandatory and discretionary spending. Because legislation authorizing a sale is a change in permanent law, it would generate pro-

ceeds from the asset sale and lose offsetting receipts from future power sales. A CBO cost estimate would attribute those changes in mandatory spending to the bill. Funds for power operations, however, are subject to appropriations; thus, savings from avoided operating costs are not counted as reductions in mandatory spending. Consequently, the estimate of the effects of that legislation on mandatory spending may overstate the full budgetary cost (or understate the savings) of a sale.

The budgetary treatment of proceeds from an asset sale has changed over time. Before August 1997, for purposes of enforcing the discretionary spending limits or the pay-as-you-go provisions of the Deficit Control Act, that act directed that proceeds from the sale of government assets not be included in legislative cost estimates. With passage of the Balanced Budget Act of 1997, however, the Congress amended the Deficit Control Act to cause such proceeds to be included in legislative cost estimates unless the sale of the asset would result in a financial cost to the federal government. Scorekeeping guidelines included in the statement of managers for the Balanced Budget Act defined the financial cost of a sale as the net present value of all changes in expected cash flows. The cash flows to be included in that financial cost are the proceeds from the sale, any change in revenues resulting from special tax treatment specified as part of it, the loss of future offsetting receipts, and savings from reductions in federal spending (whether discretionary or mandatory). The discount rate for converting future cash flows to present values is to be the interest rate on applicable Treasury securities plus 2 percentage points.

For purposes of enforcing the limits on spending of the Budget Act, the treatment of proceeds from asset sales has been governed by provisions in the annual budget resolution. The budget resolutions originally prohibited counting sale proceeds against those limits, then required counting them, and for fiscal year 1998 established a present-value test for counting them that was similar to the yardstick now included in the amended Deficit Control Act. The scorekeeping guidelines adopted in conjunction with the Balanced Budget Act of 1997 apply to enforcement of the Budget Act as well as the Deficit Control Act. Thus, in the absence of different instruction in future budget resolutions, cost estimates for Budget Act purposes will follow the same financial test for including sale proceeds as the one that applies to the Deficit Control Act.

of direct appropriations or explicit borrowing authority, to pay for those nonfederal expenditures. New subsidies or third-party financing would reduce the budgetary income from future program operations. Third, the market value of the power programs might be greater than assumed here if parts of the program were sold independently—such as transmission systems or particular generating projects—or if the sale included associated nonpower assets.

CBO's analysis of long-term budgetary effects does not represent an official estimate of the changes in budgetary receipts or outlays that could result from legislation requiring the sale of federal power assets. The Congressional Budget Office prepares those legislative cost estimates for purposes of budget enforcement and follows guidelines that would cause such estimates, prepared on a cash-value basis, to differ from the present-value estimates of long-term budgetary effects (see Box 3).

The separate budgetary treatment of mandatory and discretionary spending causes perhaps the greatest difference between legislative estimates and the long-term effects reported here. An estimate of the cost of legislation authorizing a sale of power assets would reflect only changes in mandatory spending, which would include the proceeds from the sale and the loss of future power receipts. Savings in discretionary spending for power operations would be scored separately, in annual appropriation bills. Other differences include the discounting of future values, the period of estimation, and the treatment of changes in tax receipts. The Joint Committee on Taxation, not CBO, would be responsible for estimating any change in tax receipts that might be attributed to particular legislation.

The Budgetary Impact of Power Operations: Power Receipts and Program Outlays

In general, the budgetary impact of operating the federal power program reflects two basic factors: the total amount of program spending for operation and construction each year, and the receipts from power customers. Under current law, each federal agency must set rates for the electricity it sells so that, over time, the

revenues from sales will be sufficient to offset the program's costs for routine operations, capital projects (including interest charges), and certain nonpower activities. If electricity customers ultimately pay for all of the costs of the services they receive, the federal power programs should cost the government nothing in the long run.

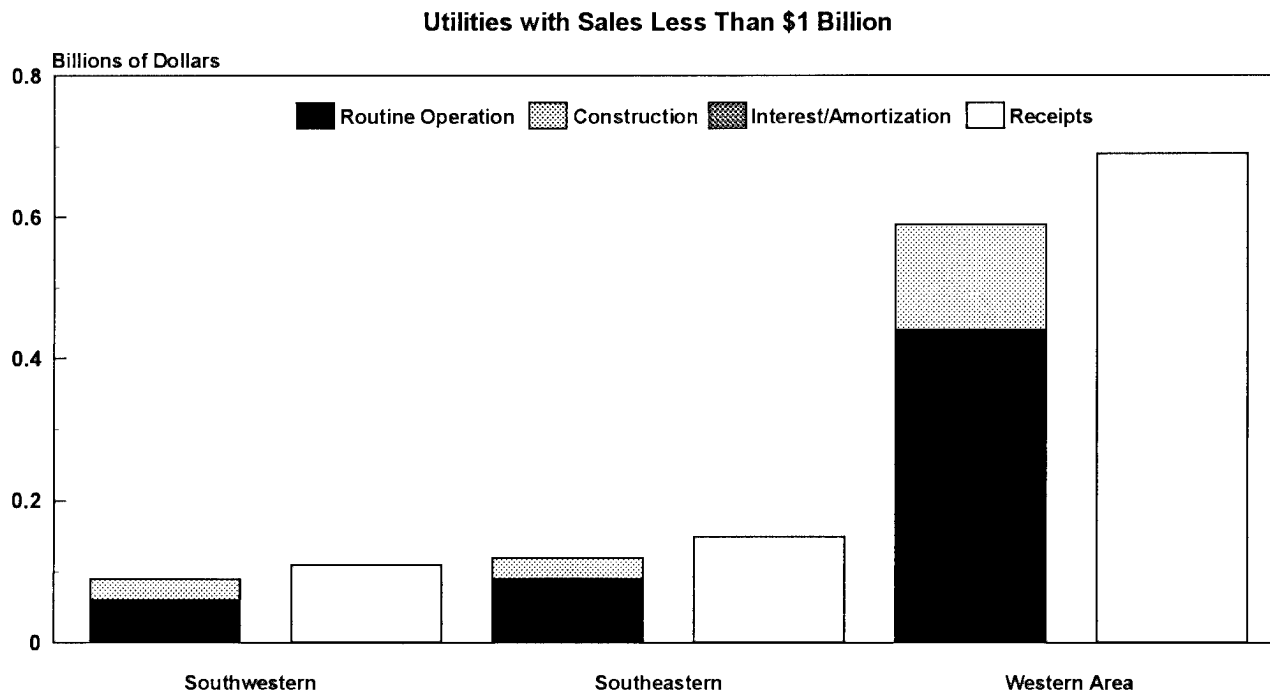
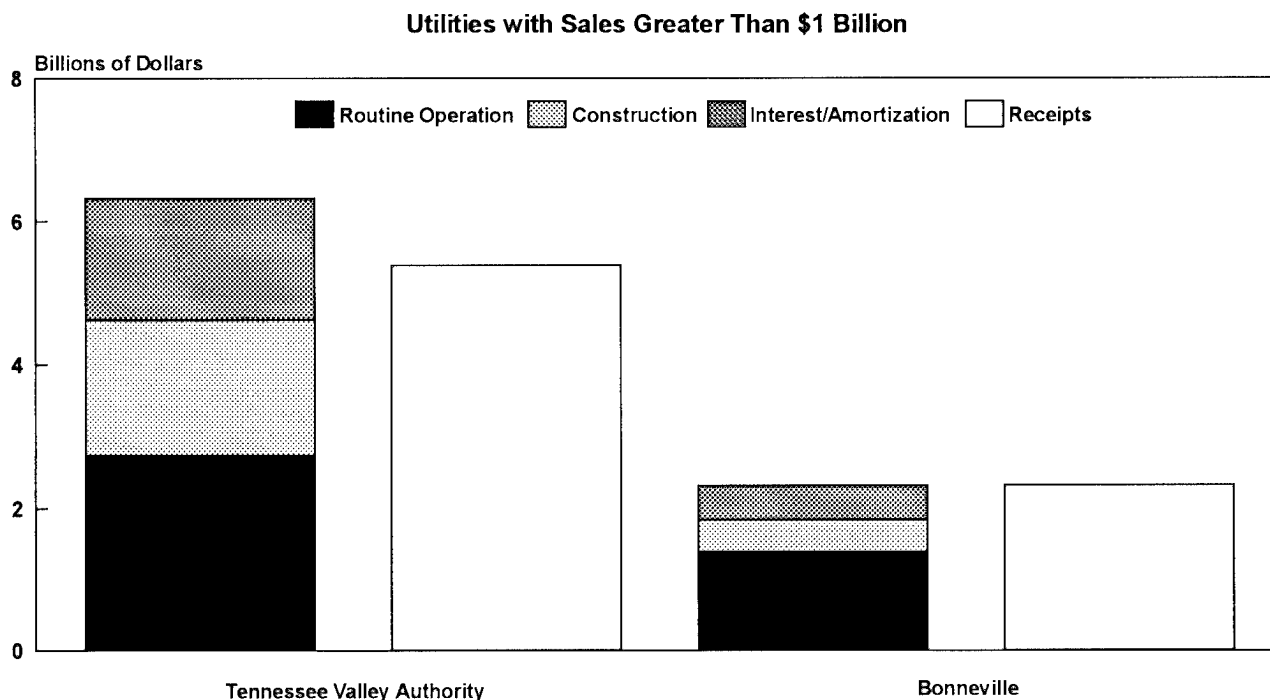
But recovering all the costs can take a very long time. In the interim, annual revenues and costs may diverge significantly. The main reason is that federal agencies, like all regulated utilities, establish power rates that treat operating costs and capital costs differently. Federal power rates include a component for current operating costs, so that customers generally pay for those costs as they occur. But power rates reflect only the costs of capital projects through depreciation and interest charges; therefore, there is a lag between the expenditure on capital by a federal agency (and by other utilities) and the ultimate reimbursement from customers. For example, outlays for large capital projects take place within a few years, but power rates may recover those costs only over the next 10 to 50 years, depending on the life of the investment.

Current Budgetary Impact of Operations Reflects Status of Capital Program

The implications of cost-recovery methods for identifying the budgetary impact of federal power operations are straightforward. In a typical year, the routine operating costs of the TVA and the PMAs are largely offset by electricity receipts from customers in that same year. Thus, the extent to which a program's net outlays are positive (net spending) or negative (net receipts) depends primarily on the difference between new capital spending and past capital recovery.

All of the federal power agencies collected more money from customers in 1995 than they spent on routine operating costs—including expenditures for power operations and maintenance and for certain nonpower programs that are a part of the agencies' rate base (see Figure 5). In that year, the federal power programs had receipts from nonfederal customers totaling \$8.7 billion, compared with routine operating expenditures totaling \$4.7 billion. The programs had an operating

Figure 5.
Federal Utilities' Spending and Receipts, Fiscal Year 1995



SOURCE: Congressional Budget Office using information from the 1995 annual reports of the Tennessee Valley Authority and the power marketing administrations.

NOTE: Revenues for the Bonneville Power Administration exclude the Treasury credit against the annual payment (\$56 million) for current fish and wildlife costs. Interest and amortization for the TVA and the BPA are for publicly held debt.

surplus—that is, net budgetary receipts—of about \$4 billion that year because their customers were still paying back the \$48 billion invested by the government for power facilities, plus associated interest charges.

Future Budgetary Impact Reflects Forgone Income

Over time, the budgetary impact of selling power assets that the government now holds would reflect the value of the future stream of net power receipts that the government would forgo. Evaluating the budgetary impact of selling today's assets means ignoring assets the government may acquire in the future and, as a result, future outlays for capital spending. If operating costs are fully recovered as they occur and new capital spending can be ignored, the net power receipts that are forgone will equal what the government would otherwise collect to finish repaying past capital spending.

Each of the federal power programs keeps data indicating when funds must be collected from customers to recover the costs of past capital investments. To determine the present value of future payments on principal and interest—for completed plants, work in progress, and (especially for the TVA and the BPA) canceled projects—CBO relied on agencies' repayment schedules for capital spending through 1995. (In the absence of new program subsidies, omitting new capital spending should have little impact on the estimation of net outlays in the long term because that spending would trigger new collections from rate payers to pay off the debt.) The analysis discounts the income due over the next 30 years (a general estimate for the remaining productive life of those assets) at a rate of 7 percent (the current cost of federal borrowing for long-term debt). That accounting ignores government costs for preparing a sale. For a 1995 proposal to sell assets of the Southeastern Power Administration, CBO estimated that such costs could equal \$6 million.²

On that basis, the present value of future payments on debt—and the budgetary impact of continuing the federal power program—is about \$46 billion (see Table 13). For each agency, that value reflects three basic

factors: the original size of the investments, the age of the investments (old projects are booked at preinflation costs, and the investments have had time to be paid off), and past repayment activity (payments can be rescheduled). Whether future market conditions may constrain future payments on debt depends on current federal rates (and how far below market rates they are) and the productivity of federal investments (incomplete or canceled projects do not support sales). In general, the budgetary value to the government of keeping power assets is greatest for the agencies that have the largest outstanding debts and the highest interest costs.

Accordingly, the loss of budgetary income from selling the assets of the Southwestern, the Southeastern, and the Western Area Power Administrations would be small: the original investments were generally small (compared with those of the BPA and the TVA) and were largely completed several decades ago. Altogether, the present value of the future net income from SWPA, SEPA, and WAPA operations—\$4.5 billion—represents about 50 percent of the government's historical expenditures on power assets for those agencies, excluding work in progress on the SEPA's Russell Dam.

By contrast, the greatest loss of potential income would come from selling the agency with the largest debt: the Tennessee Valley Authority (see Box 4). The present value of the TVA's future net income—\$28 billion—represents more than 80 percent of the government's historical expenditures on power assets for that agency. Much of the TVA's capital investment in coal and nuclear plants, including more than \$6 billion for deferred (that is, inactive but not yet canceled) nuclear plants, was made in recent decades.

Similarly, the present value of future income from the Bonneville Power Administration—\$13.6 billion—represents about 70 percent of the government's past expenditures on power assets for that program. Much of the BPA's hydropower capacity was completed more than 40 years ago, but half of the agency's current debt obligations are for nuclear plants started in the 1970s. The BPA owes \$4.4 billion for canceled nuclear plants and \$0.7 billion for environmental projects, which, although fully represented in the agency's rate base, do not contribute to power sales.

2. Cost estimate of a reconciliation proposal to sell the Southeastern Power Administration, in a letter from the Congressional Budget Office to the House Committee on Resources, October 10, 1995.

Table 13.
Comparison of Net Budgetary Receipts, Additional Tax Receipts from the Sale of Federal Power Assets,
and Market Valuations (In billions of dollars)

	Tennessee Valley Authority	Power Marketing Administrations				Total
		Bonne- ville	South- western	South- eastern	Western Area	
Present Value of Net Budgetary Receipts with Full Repayment of Past Investments ^a	28.0	13.6	0.4	1.1	3.0	46.1
Present Value of Addition to Federal Tax Receipts Caused by Increased Output ^b	0	0.4	c	c	0.1	0.5
Market Valuations, with Open Sale to Highest Bidder						
Low market value	22.4	14.6	1.3	1.0	6.1	45.4
High market value	30.5	19.9	1.7	1.4	8.3	61.9

SOURCE: Congressional Budget Office.

- a. Excludes present value of the possible repayment obligation for the incomplete portion of the Southeastern Power Administration's Russell Dam project. The face value of that inactive investment is about \$0.4 billion.
- b. For the Tennessee Valley Authority, the estimates assume that new ownership would not raise output in relation to what current government management will accomplish on its own. For the power marketing administrations, receipts are calculated as 25 percent of the 5 percent increase in current power sales (based on data from the 1995 annual reports), valued at current federal rates for power, and discounted over 30 years at 7 percent.
- c. Less than \$50 million.

Agencies may have to raise rates in the future to assure sufficient income to meet repayment obligations. For the smaller power agencies—the SWPA, the SEPA, and the WAPA—that would not be a difficult prospect; current pricing policies have left federal power rates far below market rates in parts of the country. Indeed, the basic design of the federal power programs assured that they would *not* result in the highest power rates possible. The law requires federal agencies to sell electricity to their customers at cost, consistent with sound business practices.

The Budgetary Impact of Changing Tax Receipts

Tax receipts can affect the estimation of total budgetary savings from an asset sale in two ways: through tax liabilities, which lower the market's assessment of future cash flow and therefore the market value of federal assets, and through net changes in tax receipts to the

federal government. Long-term budgetary savings should reflect the sum of sales proceeds and any net change in tax receipts minus the value of forgone net receipts from program operations. In general, if the efficiency gains from new ownership are small, the net change in tax receipts will be small, too. CBO estimates that future increases in federal taxes will total \$0.5 billion in current dollars (see Table 13).

Tax Liabilities Diminish Market Value

Any liability for federal, state, and local taxes diminishes a purchaser's future cash flow from federal power assets. As a result, the market value of those assets, the potential proceeds from their sale to the highest bidder, and the future budgetary savings from their sale are all diminished as well. The drop in savings that can be attributed to the effect of federal tax liability on sales price is offset by future direct payments of federal taxes by the purchasing firm. However, total federal tax receipts, which are important for estimating budgetary savings, may not change.

Federal Taxes Depend on National Income

Additional changes in federal tax receipts will result from a sale only as an indirect consequence of changes in national economic output or changes in the national mix of taxable income. As a rough rule, the change in federal tax receipts reflects the product of the marginal tax rate—generally around 25 percent for wages, interest, business income, and corporate income—and any change in the value of economic output. Any increase in the new owner's taxable income from raising power

rates would not constitute a net addition to federal receipts, because that income would occur at the expense of diminished income in other sectors of the economy.

Accordingly, CBO estimates that additional tax receipts from the sale of PMA assets (including the power-related assets of Reclamation and the Corps) will be 25 percent of the present value of the increase in power output with private management—assumed to equal 5 percent of current PMA sales, valued at current federal power rates. No additional tax receipts will come from privatizing the TVA's assets, because CBO assumes that the increase in sales under new ownership

Box 4.

Financial Challenges to the TVA and the BPA

The Tennessee Valley Authority (TVA) and the Bonneville Power Administration (BPA) face special challenges to their future earnings potential, primarily because their repayment obligations include large expenditures on unproductive nuclear projects. They also face difficulties in covering their capital obligations because of market pressures on power rates, outside competition from both electricity and natural gas for the business of their customers, and internal cost pressures. Both agencies now earn sufficient revenues to service their public debts, but the requirements of interest and principal payments greatly diminish the flexibility they have to lower power rates.

The TVA is experiencing a special challenge as it returns two nuclear projects—Watts Bar 1 and Browns Ferry 3—to full service, raising total generating capabilities beyond what regional customers may be willing to pay for over the next few years. Even though sales do not yet reflect the full generating capacity of those nuclear projects, under current rate-setting policy the TVA power rates should reflect the full depreciation for that capacity and the interest costs for funds used during their construction. For the TVA, raising or even holding power rates constant in the face of new competition will be especially difficult. Competition comes directly from natural gas, a source of energy for home and business heating and for private generation of electricity. Also, customers on the fringe of the TVA service area may choose alternative suppliers, although they must give 10 years' advance notice before leaving the TVA system. (To ease those cost pressures, the TVA has ex-

pressed interest in selling power outside its service area, earning income from the Department of Energy to process nuclear fuel, and refinancing some high-cost debt.) The TVA recently announced its intention to raise power rates in 1998—its first increase in 10 years.

The Bonneville Power Administration will be challenged to hold onto customers in an increasingly competitive environment. Pressures on BPA power rates have come from the rising costs of its nonpower programs—including the residential exchange program and fish and wildlife projects—and from the constraints that environmental concerns place on the diversion of water for generating hydropower. Past commitments to pay for irrigation assistance will add to the BPA's costs in the future.

On the demand side, competition in the Northwest has meant that BPA customers have the incentive and the ability to switch to independent power supplies, largely generated by natural gas. (The BPA's preferred customers are not bound by the same advance-notice obligations that restrict TVA customers, although the BPA is developing new marketing incentives to encourage its customers to sign long-term agreements.) Competition has also meant a slowdown of growth in demand and the emergence of excess generating capacity for California, the Far West's largest electricity market. Thus, California utilities may not buy as much BPA power in the future and may even want to send more of their own excess into the BPA service region.

only matches the increase that will probably take place under continued government management. That is, the increases in future output by the TVA will produce additional taxable income, too.

The gain in power output (and efficiency of private production) for individual assets may not correspond exactly to the gain in national output (and social efficiency). Any rise in national output as a result of privatization would also reflect the benefits of market-based pricing (including improved decisions about consumption by power customers) and better allocations of resources throughout the economy. Such social gains are difficult to assess. For example, resources displaced either by increased power output—for example, in the production of natural gas, heating oil, or power from other sources—or by reduced operating costs may not be readily reemployed in other activities. The actual amount of displacement—and hence the ultimate social gain from privatization—may depend in part on current market conditions. Also, some economic resources will be diverted to conducting the sale and integrating federal assets into private systems. In the short term, transaction costs may reduce economic output before any gains in power output can accrue.

Taxes Also Depend on Income Mix

The only general tax effects of a change in ownership, aside from any change in national output, would be produced by a shift in the economy's mix of taxable income. Under federal ownership of power assets, power receipts are now used to pay for employees and contractors of power agencies, interest on the federal debt resulting from power investments, and government spending not related to power programs—all three of which are sources of taxable income. Under private operation, the mix of taxable income would probably shift initially to include more income from business and, depending on how the owner financed the purchase, less income from interest. (Federal payments of interest would decline because the sale proceeds would reduce the national debt.) The marginal tax rates for personal, business, corporate, and interest income are very similar. This analysis therefore assumes that total tax receipts do not change because of changes in the income mix.

Assumption of a 5 Percent Gain in Output Yields a Modest Tax Gain

Counting only the present value of federal tax receipts that can be ascribed to a 5 percent increase in PMA power sales (valued at current power rates) would raise the total budgetary savings from the sale of all federal power assets by about \$0.5 billion. This study does not attribute any change in net tax receipts to a sale of TVA assets; based on existing generating capacity, CBO assumes that under continued federal operation, the TVA would raise output by the same amount as a new owner.

For the sake of comparison, the present value of federal taxes that nonexempt private purchasers of federal assets would pay directly, based on the low and high market valuations, would be between \$8 billion and \$12 billion, respectively. Those figures assume tax savings from interest deductions by the new owners on the basis of 50 percent debt financing. However, such interest deductions would be offset by new interest earnings by lenders. Similarly, increased power rates and taxable income for the new owners would reduce taxable income in the sectors of the economy that consume power.

CBO presents estimates of revenue changes for information purposes only and does not suggest that cost estimates of Congressional legislation would include any such effects for scoring purposes. Congressional estimates typically cover a period of five to 10 years into the future, and the assumptions underlying CBO's illustrative estimates may not hold over that period. Also, legislation privatizing certain federal power programs could require the private sector to incur various transaction costs in the short term that could cause total taxable income and tax revenues to decline, not increase, as in the illustrative CBO estimate. The Joint Committee on Taxation is responsible for estimating the expected change in revenues, if any, that CBO would include in its legislative cost estimate.

The Prospects for Long-Term Budgetary Savings

Long-term budgetary savings from selling power assets, in present-value terms, require that the sales pro-

ceeds, plus any increase in tax receipts after the sale, exceed the present value of the net receipts that the government gives up. In this analysis, CBO considers the potential budgetary savings from the unrestricted sale of all power assets (including the power-related assets of Reclamation and the Corps) to the highest bidder under alternative assumptions about the future course of power rates. On that basis, the potential budgetary savings could be worth as much as \$16 billion in current dollars if all assets sold for high market values (see Table 14). If market value was low, however, a small budgetary cost of \$0.2 billion could result because losses from selling TVA assets just offset the combined savings from selling the PMA programs.

In general, the prospects for budgetary savings increase for agencies when the new owner can boost cash flow by selling power at higher rates or lower costs than the government. The prospects for savings diminish when the government must collect large sums to repay past investments and when market conditions permit that collection. That view largely explains this study's basic findings about budgetary effects.

Budgetary Savings from Selling TVA Assets Require a High Market Value

Selling the Tennessee Valley Authority's assets would yield long-term budgetary savings worth \$2.5 billion in

today's dollars if they were sold at the high market value of about \$30 billion. But a sale at the low market value of about \$22 billion would yield budgetary costs, not savings, of \$5.6 billion.

The general pattern of small budgetary savings or even costs from selling TVA assets has as much to do with the TVA's financial problems as with its successes. The value to the government of future net receipts from TVA power sales is great because the agency has large debt obligations. By contrast, the market value to potential purchasers of TVA assets would be limited by the fact that market circumstances would probably restrict the buyers' ability to increase the earnings potential of TVA assets significantly, either by raising rates or increasing production. In 1995, the TVA's rates for wholesale power sales were only about 0.5 cents per kilowatt-hour, or 10 percent, below the average rate that investor-owned utilities in the Southeast charged municipal utilities and cooperatives. And the TVA is already operating its on-line coal and nuclear units at utilization rates close to industry norms.

General Budgetary Savings Accrue from Selling PMA Assets and Related Assets of Reclamation and the Corps

Selling the power assets of the Bonneville Power Administration, including the power-related assets of the

Table 14.
Comparison of Potential Budgetary Savings or Costs from the Sale of Federal Power Assets Under Varying Assumptions About Market Value (In billions of dollars)

Assumption	Tennessee Valley Authority	Power Marketing Administrations				Total
		Bonneville	Southwestern	Southeastern	Western Area	
Low Market Value	-5.6	1.4	0.9	a	3.2	-0.2
High Market Value	2.5	6.7	1.3	0.4	5.4	16.3

SOURCE: Congressional Budget Office.

NOTE: Budgetary savings are calculated as the market value plus the present value of the addition to tax receipts minus the present value of net budgetary receipts from repayment of all past investments. Negative values indicate budgetary costs.

a. Between zero and -\$50 million.

Bureau of Reclamation and the Corps of Engineers, would produce long-term budgetary savings under a range of assumptions about market value. Savings could be as high as \$6.7 billion for a sale at the high market value, or as low as \$1.4 billion at the low market value. The opportunity for budgetary savings from selling the power assets supporting the BPA results in part because the historical costs of federal hydropower projects in the Northwest—largely completed by the early 1950s—are so low. Even when the canceled nuclear projects of the Washington Public Power Supply System are added in, the obligations of the BPA for capital repayment are small in relation to the current earnings potential of those early hydropower projects.

The market valuations also contribute to the prospect of budgetary savings from the BPA. Both valuations reflect the earnings potential implicit in the difference between BPA power rates and average market rates in the Northwest and the opportunity to raise the efficiency of production. It is difficult to know just how much a new owner could actually raise rates, because rates for incremental sales by private suppliers are currently about one-half of the average cost for power in the region. Certain BPA customers would be able to purchase some power—for interruptible service or peak load—at those lower incremental rates. A sale of BPA assets, however, could still be close to deficit neutral if power rates rose by only 0.5 cents per kWh—or less than half the increase of 1.3 cents per kWh that this analysis assumes. (A rise of 0.5 cents per kWh would represent a 20 percent increase over current rates to preferred utilities.)

Federal power rates are far below market rates for the Southwestern and Western Area Power Administrations, both on average and for incremental sales. As a result, a new owner could easily increase cash flow by raising rates. Moreover, the budgetary value to the government of keeping those programs is relatively small. One reason is that each agency has made significant progress in repaying its capital costs. Another is that nearly one-half of the generating capacity for each of those agencies is at projects that came on line before 1960. Thus, the current earnings potential of those facilities is much greater than their original costs. The budgetary savings from selling those two programs and the associated power assets of Reclamation and the Corps total \$6.7 billion for a sale at a high market value and \$4.1 billion at a low market value. With low repay-

ment obligations, market valuations would support a deficit-neutral sale of SWPA assets if power rates rose by only 15 percent, or 0.2 cents per kWh (in contrast to the increase of 1.9 cents per kWh assumed here). A sale of WAPA assets would be deficit neutral if power rates rose by only 25 percent, or 0.5 cents per kWh (in contrast to the increase of 1.9 cents per kWh assumed here).

For the Southeastern Power Administration, the budgetary effects range from small savings (\$0.4 billion) for a sale at the high market value to a negligible budgetary cost (less than \$50 million) for a sale at the low price. That is, such a sale would be close to deficit neutral. Both market valuations of SEPA assets reflect limited opportunities for bidders to raise rates and the relatively low productivity of SEPA projects. After the TVA and the BPA, the Southeastern Power Administration charges the highest rates for federal power (2.8 cents per kWh).

As with the BPA, the SEPA's power rates are already close to those charged by private generators for incremental supplies, so it is not clear how much a new owner might actually be able to raise rates. The market valuations for the SEPA, however, are buoyed by the low generating levels from Corps hydropower projects—and the potential for gains in efficiency. For example, the SEPA had access to about 50 percent more generating capacity in 1995 than did the SWPA but sold about 10 percent less power—indicating that it had the lowest generating efficiency of all the federal programs. The prospects for long-term budgetary savings from the sale of SEPA assets may be higher than those indicated here if efficiency gains from private operation turn out to be greater than the 5 percent that the market valuations assume.

Other Considerations Enhance Prospects for Budgetary Savings

If debate over what to do about the TVA and the PMAs goes on for several years, the market valuations and budgetary impact that ultimately determine the level of budgetary savings from privatization could look very different than this study assumes. For several agencies,

the present value of budgetary savings is small in relation to the value of program assets. In those cases, small changes in the assumptions could easily suggest the possibility of budgetary costs, not savings, as a result of their sale (see Appendix B). In particular, if increased competition causes power rates to decline in the future, rather than hold steady or rise, market values will be lower than assumed. But in general, a number of considerations make it more likely that the actual budgetary savings from the sale of power assets will be greater than shown here.

First, the budgetary impact omits certain costs that are not currently a part of the federal rate base. Second, the budgetary impact does not include the prospect of new subsidies, new capital expenditures that will not be fully repaid, or new obligations that the power agencies may incur through third-party financing. And third, the market assessments do not include the value of associated nonpower assets that could be a part of the sale. Nor do they consider the prospect that new owners may find new uses for or combinations of power assets that can increase their earnings potential. The combined value of the individual pieces of the federal power program, sold separately, may be greater than the value of the program as a whole.

Current Budgetary Outlays Not Covered by Power Receipts

The General Accounting Office (GAO) has recently identified a number of current budgetary costs that are not passed on to PMA customers.³ Among those costs are subsidies to rate payers that include retirement benefits and postretirement health benefits for federal employees, capital costs misallocated to incomplete irrigation projects, and certain environmental expenses. CBO's analysis omits those costs under the assumption that the government would retain those liabilities whether or not the power programs were sold. (According to the President's most recent budget submission, the PMAs will begin to recover the full cost of retirement benefits and postretirement health benefits

through power rates in fiscal year 1998.)⁴ A second category of subsidy addressed by the GAO and of direct concern here is related to the possibility that the power agencies may not recoup certain capital costs for incomplete projects.

Future Budgetary Costs of Program Operation

Policymakers may also want to consider the potential budgetary impact of continued government ownership in the near term. Future costs may come from several directions. For existing projects, any action by the Congress or federal agencies to hold down federal power rates by stretching out capital repayment schedules, allowing agencies to repay certain high-cost loans from the Treasury early, or forgiving repayment altogether will diminish the present value of forgone net receipts and, hence, enhance the budgetary case for selling federal assets.

For new projects that would benefit from government support (for example, in the form of below-market interest rates or, for multiple-use projects, favorable cost allocations), selling the power agencies could yield additional savings from subsidies that were avoided. New spending on capital projects is probable. One reason is that to operate efficiently, each of the power agencies will have to invest continually in projects to replace or upgrade their generating and transmission systems. Indeed, the need for significant capital improvements to the nation's aging dams may be just around the corner—as evidenced, for example, by the failure of a spillway gate at California's Folsom Dam in 1995 and the consequent draining of the reservoir.

Other likely reasons for new capital spending are easy to identify. Proposals have already been made to fund the new Auburn Dam in California. The TVA has kept incomplete nuclear projects in a "deferred" status—rather than canceling them outright—in anticipation of finding some new way to make them economic.

The appropriation process and, for the TVA and the BPA, limits on borrowing, may not be able to constrain those future costs because the power agencies use

3. General Accounting Office, *Power Marketing Administrations: Cost Recovery, Financing, and Comparison to Nonfederal Utilities*, GAO/AIMD-96-145 (September 1996).

4. *Budget of the United States Government, Fiscal Year 1998: Appendix*.

third-party financing. Appropriations generally limit the capital spending of the SWPA, the SEPA, the WAPA, the Bureau of Reclamation, and the Corps of Engineers. Caps on public borrowing by the TVA and Treasury borrowing by the BPA (for transmission projects) limit the capital spending of those agencies. But third-party financing of projects can remove those limits on agency spending. For example, through such accounting devices as net billing, an agency can make a long-term arrangement with a nonfederal entity that will supply power or build, maintain, or operate facilities to supply power for federal sale. The agency can "pay" for those services by selling federal power at a discount to the nonfederal entity or buying nonfederal power at a high cost.

Policy Concerns Other Than the Budget

Balancing the budget may not be the only or even the paramount concern facing the Congress in its decisions about the future of federal power. If nonbudgetary concerns are important, reliance on budgetary assessments—such as those outlined here—can send the wrong signals to decisionmakers. In particular, using the federal cost of borrowing to discount future government income tilts the decision to sell away from what might be economically most efficient. Budgetary assessments may also say little about whether a sale of assets supports or hinders other social goals that federal power was intended to remedy, such as promoting rural development or competition.

Budgetary Savings Do Not Reflect Gains in Economic Efficiency

In general, the government attaches greater value to a given income stream for budgetary purposes than would a private entity for the purpose of earning a profit. Government and private operators may value future income differently because of differences in discount rates and tax liabilities. Those considerations are not related to differences in their assessments of future cash flow based on outlooks for market conditions.

The federal government can realize long-term budgetary savings from any investment it makes (including retaining ownership of power assets) that yields a return greater than the federal cost of borrowing—currently about 7 percent a year. That is, the appropriate discount rate on government income for budgetary purposes is 7 percent. By contrast, the yield that private firms require from investments is generally higher, reflecting the after-tax return they can earn elsewhere. For a partially debt-financed acquisition of power assets, this study assumes a private-sector discount rate of 10 percent.

The liability for federal taxes drives an additional wedge between market valuations and estimates of budgetary impact. Taxes diminish the cash flow on which a business would base a bid for federal assets. But unless the change in ownership would also enhance efficiency throughout the economy and raise national income, no net increase in federal taxes would offset the loss of budgetary income from program operations after the sale.

Therefore, as long as the basis for decisions about selling power assets rests on budgetary savings alone, the difference in discount rates and tax liabilities will bias government decisions against a sale. As this study has noted, however, budgetary considerations need not—or perhaps should not—be the only reason for keeping or disposing of federal assets. If the criterion for a sale is economic efficiency for the nation as a whole, it would be appropriate to discount the government's net receipts from the operation of power programs by the higher private-sector rate. That way, basing the choice of owners—government or private—on present-value calculations would yield the most economic use of the nation's resources. More direct yet, the analysis could simply focus on available estimates of potential efficiency gains.

To illustrate the effect of efficiency gains on market valuations, CBO has evaluated a 5 percent increase in power output for the PMAs over current levels—a figure well within the range suggested by past differences between the productivity of federal and nonfederal hydropower operations. But, as summarized in Chapter 3, efficiency gains from private ownership may also result from improving the current management structure and imposing economic constraints on financing decisions and price setting.

The Continuing Relevance of Past Social Concerns

The Congress has invested in power facilities over the years, not only to supply power but as a way to fund nonpower activities such as irrigation and flood control, promote rural economic development through low power rates, and correct certain market failures. Meeting some of those nonpower objectives may be easily

manageable with the private operation of power facilities; private ownership may complicate meeting others. Because federal operation of power facilities is necessary to meet certain nonpower objectives, estimates of budgetary savings may overestimate the net benefits of ending that federal role. Indeed, the ultimate savings from a sale of assets will depend on the extent to which the government continues to support those goals in the future.

Appendixes

Federal Power Sales by State

This appendix supplements the data on federal power sales to states presented in Chapter 1. Table A-1 gives the following information for each of the 36 states receiving federal power in fiscal

year 1995: the federal sales to different groups of customers, the total federal sales, and the total federal sales as a percentage of total power consumption from all sources.

Table A-1.
Federal Power Sales to Utilities and Direct Customers, Fiscal Year 1995
(In millions of kilowatt-hours)

	Publicly Owned Utilities	Coop- eratives	Investor- Owned Utilities	Direct Sales		Total Federal Sales ^b	Federal Share of State Total ^c (Percent)
				Industrial	Other ^a		
Alabama	10,711	4,072	0	4,497	61	19,342	25.8
Alaska	85	73	246	0	4	408	7.0
Arizona	1,469	27	245	107	881	2,729	5.6
Arkansas	694	706	0	0	0	1,400	3.8
California	8,679	166	4,835	0	1,646	15,327	6.9
Colorado	637	1,119	111	0	80	1,946	5.5
Florida	58	141	33	0	0	233	0.1
Georgia	769	4,525	0	0	0	5,294	5.2
Idaho	977	1,549	197	0	0	2,723	13.8
Illinois	21	42	0	0	0	62	0
Iowa	691	528	289	0	0	1,507	4.3
Kansas	551	458	0	0	0	1,009	3.3
Kentucky	3,110	2,544	0	7,839	38	13,531	18.2
Louisiana	162	352	0	0	0	515	0.6
Minnesota	1,265	599	1,029	0	41	2,893	5.2
Mississippi	3,277	5,621	0	3,067	0	11,965	29.6
Missouri	898	1,835	5	0	0	2,738	4.4
Montana	15	1,527	725	2,674	262	5,203	38.4
Nebraska	1,793	0	0	0	232	2,025	9.7
Nevada	1,288	661	69	0	21	2,039	9.8
New Mexico	151	711	17	0	190	1,069	6.4
North Carolina	224	1,111	0	7	0	1,343	1.3
North Dakota	142	906	38	0	98	1,184	14.7
Ohio	2	0	0	0	0	2	0
Oklahoma	386	985	0	0	0	1,371	3.2
Oregon	7,113	4,017	4,344	3,281	4	18,759	40.6
South Carolina	463	443	0	0	0	907	1.3
South Dakota	692	1,016	35	0	142	1,885	25.4
Tennessee	60,583	5,395	0	8,491	169	74,638	88.4
Texas	253	1,000	30	0	0	1,283	0.4
Utah	1,168	390	6	0	74	1,638	8.7
Virginia	568	197	0	0	0	765	0.9
Washington	25,065	2,863	3,339	14,782	799	46,848	52.5
West Virginia	0	0	1	0	0	1	0
Wisconsin	39	50	0	0	0	89	0.1
Wyoming	47	531	0	0	17	595	5.1

SOURCE: Congressional Budget Office using data from the Energy Information Administration, Forms EIA-860 and EIA-867. Data for sales to publicly owned utilities, cooperatives, and investor-owned utilities are preliminary.

- a. Other direct sales include sales to retail customers served by the Bureau of Indian Affairs.
- b. Federal data exclude sales and transfers to federal agencies and other public institutions.
- c. State total reflects retail power sales by utilities plus self-generation and consumption by nonutilities.

Cash Flows for Federal Utilities and Sensitivity Analyses of Market Values and Budgetary Effects

This appendix describes the derivation of the net cash flows that serve as the basis for the study's market valuations. It also presents a sensitivity analysis for those valuations and for the budgetary effects described in the study.

Net Operating Income, Net Cash Flows, and Discount Rates

The Congressional Budget Office (CBO) used program data to estimate net operating income for each federal power agency. Those data are shown in Tables B-1 and B-2. Net operating income, along with assumptions about taxes and future income growth, yield estimates of future net cash flows that are the basis for high and low market valuations.

Current operating data for the power marketing administrations (PMAs) come from the statements of revenues and expenses appearing in the PMAs' 1995 annual reports. For the Tennessee Valley Authority (TVA), the data represent revenues and expenditures for 1996. The reason for using 1996 information for the TVA was to obtain a picture of that agency's cash flow after the Browns Ferry 3 and Watts Bar 1 nuclear units had entered service. The study assumes that the

remaining levels of capital expenditures that the TVA and the other agencies report represent a routine amount that a new owner would have to spend every year, along with outlays on operations, to keep producing power. (That approach does not distinguish new

Table B-1.
Income and Expenditures for Power Programs
of the Tennessee Valley Authority,
Fiscal Year 1996 (In millions of dollars)

	Amount
Income from Program Operations	5,693
Program Expenditures	
Generating, transmission, and marketing	1,218
Purchase of power and fuel	1,278
Construction (Capital expenditures)	1,107
Payments in lieu of taxes (PILT)	256
Interest costs	<u>2,083</u>
Total	5,942
Net Income from Program Operations	-249
Net Income Without Interest and PILT	2,090

SOURCE: Congressional Budget Office using data from the 1996 annual report of the Tennessee Valley Authority.

Table B-2.
Income and Expenditures for Power Marketing Administrations, Fiscal Year 1995 (In millions of dollars)

Income and Expenditures	Bonneville	Southwestern	South-eastern	Alaska	Western Area
Income from Program Operations ^a	2,386	106	155	11	694
Program Expenditures					
Power marketing administration expenses ^b					
Transmission, marketing, and conservation	720 ^c	20	3	4	163 ^c
Purchase of power and wheeling services	161 ^d	2	31	0	85
Construction (Capital expenditures)	354	16	0	2	150
Nonpower costs					
Residential exchange program	198 ^e	0	0	0	0
Fish and wildlife programs	103	0	0	0	0
Operating expenses for the Bureau of Reclamation and the Army Corps of Engineers					
Generation	131 ^g	33	54	0	193 ^f
Construction (Capital expenditures)	64 ^g	14	29	0	h
Interest costs	<u>907</u>	<u>20</u>	<u>66</u>	<u>5</u>	<u>185ⁱ</u>
Total	2,637	105	183	11	776
Net Income from Program Operations	-252	1	-28	0	-82
Net Income Without Interest and Nonpower Costs	956	21	38	5	103

SOURCE: Congressional Budget Office using data from the 1995 annual reports of the power marketing administrations; and Department of Energy, *Fiscal Year 1996 Congressional Budget Request*, vol. 3, DOE/CR-0030 (February 1995).

- a. For the Bonneville Power Administration (BPA), expenses exclude the value of power provided for residential exchange (\$809 million). For the Western Area Power Administration (WAPA), expenses include power sales from the Navajo Generating Station marketed on behalf of the Bureau of Reclamation (\$88 million) but exclude other operating income related to the WAPA's purchased-power program (\$103 million, see footnote c).
- b. Excludes depreciation.
- c. For the BPA, excludes the cost of power purchased for residential exchange (\$1,007 million). For the WAPA, reflects the net cost of the purchased-power program, equal to the difference between the gross cost to purchase power and transmission services (\$188 million) and other program income (\$103 million).
- d. Includes investment activity for utility plant (\$281 million) and conservation (\$74 million).
- e. Reflects implementation expenses (\$71 million) and investment activity (\$32 million).
- f. Includes \$83 million from the funds the WAPA collects for power sales from the Navajo Generating Station as an estimate of routine operating costs for that plant. The WAPA reports that amount as a "net income transfer."
- g. Excludes direct funding of the activities of the Bureau of Reclamation and the Army Corps of Engineers under authority of the 1992 Energy Policy Act.
- h. Construction by the WAPA and operating agencies is included in the \$150 million in construction expenditures for the power marketing administrations.
- i. The WAPA reports total interest payments of \$185 million. CBO assumes that figure includes the current interest expense for nonfederal funding of improvements under the Hoover Power Plant Project Act (\$11 million).

capital expenditures from the new operating costs that such expenditures would produce.)

For the study, CBO assumed that a new owner would not take on the debt obligations or program costs of an agency that were unrelated to power generation and transmission. The largest costs of federal agencies unrelated to supplying power but paid for by power revenues come from three sources: the residential exchange program of the Bonneville Power Administration (BPA), in which the BPA subsidizes the cost of power to certain utilities that are not preferred customers; certain environmental activities of the BPA; and the payments that the TVA makes to local governments in lieu of taxes. (Other nonpower programs of the TVA for environmental activities, economic development, and stewardship of the river system are funded by Congressional appropriations, not power revenues.)

The net operating income that a potential buyer would look at would not include the costs for nonpower activities and interest on agency debts. CBO subsequently inflated those estimates of current net income to reflect assumptions about productivity increases, initial rate changes (increases from current federal rates to investor-owned utility rates), and future growth in net income (zero growth or growth at inflation). Productivity increases for the PMAs—equal to 5 percent of current sales at no extra cost—are related to assumed efficiency gains at federal hydropower projects, not to growth in demand. There is little untapped hydrocapacity on the nation's waterways. The assumed sales increase for the TVA pertains to increased use of existing capacity in response to growing regional demand. Assumptions about net cash flow for the TVA reflect additional costs for generating nuclear power.

In addition to net operating income, the net cash flow to a new owner reflects tax liabilities. In this study, CBO assumed a combined liability for federal and local taxes of 40 percent of income, less deductions for capital depreciation. Capital depreciation is based on the sales prices of the federal assets and an assumed remaining project life of 30 years.

The representation of tax liabilities treats all routine operating and construction costs as expensible. If the new owners must depreciate certain of those construction costs—that is, deduct them from taxable income over time—the present value of net cash flow will

be lower than that presented here. Making that adjustment, however, requires distinguishing future capital costs from the additional operating costs for the new units, identifying which of those capital costs is depreciable, and determining the appropriate depreciation schedules.

For the study, CBO assumed a discount rate of 10 percent to convert future cash flows to their present-value equivalents. The actual discount rate that a potential buyer of federal assets would apply would reflect the weighted average cost of capital for that business.¹ Weighted average cost of capital is a measure of the rate of return that the business could obtain by investing its resources elsewhere. That discount rate reflects the cost of borrowing for the business, the amount of the purchase price the business will finance by borrowing, and the return on equity (or nonborrowed funds) that the business requires.

A major uncertainty underlying the choice of discount rates is the fact that in relation to other businesses, investor-owned utilities (the most likely group to express interest in acquiring federal assets) have low borrowing costs (around 7.5 percent) and therefore tend to finance much of their acquisitions with new debt (around 50 percent). Utilities' returns on equity are about 10 percent, which suggests a weighted average cost of capital of about 8.75 percent. But some non-utility groups that have higher costs of capital may bid. Furthermore, growing competition in power markets may be changing the borrowing costs and debt structures of utilities themselves. Aside from those concerns, the range of discount rates that appear to explain major acquisition decisions by U.S. businesses is very broad.² For those reasons, CBO decided that the discount rate should be higher than 8.75 percent, but the choice of 10 percent is not based on explicit assumptions about future borrowing costs, debt structures, or returns on equity.

1. See Thomas E. Copeland and J. Fred Weston, *Financial Theory and Corporate Policy* (Reading, Mass.: Addison-Wesley Publishing, 1979) or other standard textbooks on corporate finance.
2. See Eugene F. Fama and Kenneth R. French, "Industry Costs of Equity," *Journal of Financial Economics*, vol. 43, no. 2 (1997); Steven N. Kaplan and Richard S. Ruback, "The Valuation of Cash Flow Forecasts: An Empirical Analysis," *Journal of Finance*, vol. 50, no. 4 (1995); and J.C. Bosch, "Alternative Measures of Rates of Return: Some Empirical Evidence," *Managerial and Decision Economics*, vol. 10, no. 3 (1989).

Sensitivity of Valuations of Net Cash Flow to Major Assumptions

Market valuations based on net cash flow are subject to many uncertainties. Chapter 5 reviewed the consequences of changing some of the basic assumptions of the cash flow analysis: higher and lower growth in power rates (and net cash flow), limitations on a sale to account for liabilities for nonpower programs, temporary freezes on power rates, and delays in the start-up of hydropower operations (see Table 12 on page 49). Market valuations are also sensitive to small changes in

discount rates, tax rates, and other elements of cash flow. Table B-3 summarizes the sensitivity of the high and low market valuations to those changes. (The results are approximately symmetrical for increases or decreases in the assumed values.)

In general, the results of the sensitivity analysis are not additive. All combinations of assumptions are not equally likely; many are extremely unlikely. The sensitivity results are presented here because CBO cannot know which businesses might bid for federal power assets or what their specific market assumptions might be. For anyone who has that information, the sensitivity analysis provides a quick way to see how the conclusions of this study could change.

Table B-3.
Sensitivity of Market Valuations to Changes in Key Assumptions (In billions of dollars)

Assumption	Reduction in Value	Tennes- see Valley Authority	Power Marketing Administrations				Total Change
			Bonne- ville	South- western	South- eastern	Western Area	
Low Market Value							
Discount Rate	1 percentage point	2.2	1.5	0.1	0.1	0.6	4.5
Discount Period ^a	Five years	-0.9	-0.6	b	b	-0.2	-1.8
Depreciation Schedule ^c	Five years	0.7	0.5	d	d	0.2	1.4
Effective Tax Rate	5 percentage points	1.4	0.9	0.1	0.1	0.4	2.9
Efficiency Gain	1 percentage point	-0.4	-0.2	b	b	-0.1	-0.6
Initial Increase in Power Rates	0.1 cent per kWh	-1.0	-0.6	-0.1	b	-0.3	-2.0
High Market Value							
Discount Rate	1 percentage point	3.9	2.6	0.2	0.2	1.1	8.0
Discount Period ^a	Five years	-2.1	-1.4	-0.1	-0.1	-0.6	-4.3
Depreciation Schedule ^c	Five years	1.3	0.9	0.1	0.1	0.4	2.7
Effective Tax Rate	5 percentage points	1.7	1.1	0.1	0.1	0.5	3.4
Efficiency Gain	1 percentage point	-0.5	-0.2	b	b	-0.1	-0.9
Initial Increase in Power Rates	0.1 cent per kWh	-1.3	-0.8	-0.1	-0.1	-0.4	-2.7

SOURCE: Congressional Budget Office.

NOTE: kWh = kilowatt-hour.

- a. Assumes no change in the depreciation schedule.
- b. Between zero and -\$50 million.
- c. Assumes no change in the discount period.
- d. Less than \$50 million.

Sensitivity of Budgetary Effects to Major Assumptions

The budgetary value to the government of keeping power assets—or the present value of future budgetary income, as discussed in Chapter 6—is also subject to many uncertainties. The study discusses how the budget in future years would be affected, on net, by receipts that the power agencies must collect to repay their debt

obligations, assuming that power receipts would fully cover operating costs as they occur. Budgetary effects were estimated as the present value of future debt repayments (including interest). That approach describes the maximum contribution to the budget that power agencies can make under current law.

Future market conditions—as they affect power rates, sales, or costs—may complicate or ease the agencies' task of collecting sufficient revenues. Table B-4 summarizes influences on the maximum budgetary ef-

Table B-4.
Sensitivity of Budgetary Effects to Changes in Key Economic Variables Affecting Repayment
(In billions of dollars)

Economic Variable	Change in Variable	Tennessee Valley Authority	Power Marketing Administrations			
			Bonneville	Southwestern	South-eastern	Western Area
Power Rates						
Current	Rise immediately to market levels	8.8	1.5	1.6	0.3	6.6
Future	Grow at 3 percent a year	17.1	7.0	0.3	0.5	2.3
Power Sales						
Current	Drop immediately by 5 percent ^a	-3.7	-1.5	-0.1	-0.1	-0.5
Future	Grow at 1 percent a year for 10 years ^b	1.7	*	*	*	*
Future Operating Costs ^c	Grow at 3 percent a year	-11.6	-5.3	-0.3	-0.4	-1.8
Memorandum:						
Maximum Budgetary Impact ^d	*	28.0	13.6	0.4	1.1	3.0

SOURCE: Congressional Budget Office.

NOTES: Future revenues and costs are discounted in all cases at 7 percent. The discount period is 30 years in all cases except for the 10-year sales growth for the TVA.

* = not applicable.

- Sales drop by 5 percent from current levels. Estimates do not include decreases in generating or transmission costs.
- Demand grows annually by 1 percent from current levels for 10 years to approximate the use of current excess generating capacity in the Tennessee Valley Authority system. Estimates do not include increases in generating or transmission costs.
- Includes current nonpower costs for the TVA (payments in lieu of taxes) and the Bonneville Power Administration (residential exchange program and support for environmental and fish and wildlife programs).
- The maximum budgetary impact is the present value of currently scheduled debt repayments and interest.

fects that could result from a rise in federal power rates to current market levels in each region, growth in power rates from current levels (without growth in costs), growth in sales by the TVA to fully use existing capacity (recall that the hydrocapacity of the PMAs will not support sustained sales growth), a loss of federal customers caused by competition, or growth in costs for operation and routine construction (without growth in rates). For the sensitivities on power rates, the analysis assumes the agencies have sufficient discretion to make those changes under current law.

As with the sensitivity analysis for market values, the particular budget sensitivities are illustrative, and the results may not be additive. Most important, current law would constrain federal rate setting in all cases: the maximum budgetary impact is based solely on current requirements for debt repayment. Thus, the numbers in Table B-4 simply represent potential sources of constraint on federal power income—not sources of additional income. In other words, factors associated with a positive influence on budgetary effects, such as growth in power rates or sales, can only offset the negative influence of other factors, such as growth in costs or loss of customers.