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Public Power in the U.S. Electric Utility Industry: Regulatory Issues and Comparative Financial Indicators Across Ownership Types

Lawrence J. Hill

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PUBLIC POWER IN THE U.S. ELECTRIC UTILITY INDUSTRY: REGULATORY ISSUES AND COMPARATIVE FINANCIAL INDICATORS ACROSS OWNERSHIP TYPES

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Energy and Economic Analysis Section

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ABSTRACT

PUBLIC POWER IN THE U.S. ELECTRIC UTILITY INDUSTRY: REGULATORY ISSUES AND COMPARATIVE FINANCIAL INDICATORS ACROSS OWNERSHIP TYPES

Lawrence J. Hill

By ownership type, the U.S. electric utility industry consists of (1) investor-owned utilities, (2) rural electric cooperatives (distribution and power supply cooperatives), (3) Federal power projects (the Tennessee Valley Authority and five Federal power marketing agencies with their supply sources), and (4) state/municipal systems (state projects, county projects, public utility districts, municipally owned electric systems, and joint action agencies). In 1984, public power--defined as the latter three ownership types--accounted for 23.4 percent of total generating capacity and 24.0 percent of total end-use sales in the industry. The average price of end-use electricity across all customer classes obtained by investor-owned utilities in 1984 was 6.53 cents per kilowatt-hour (kWh), while the corresponding price for publicly owned systems was 5.28 cents/kWh. A number of operating and regulatory/legislative characteristics account for this difference in average price. The focus of this report is on regulatory/legislative differences.

Differences include (1) the nature and extent of Federal and state regulation and (2) financial considerations such as sources and cost of capital, taxation, and the treatment of construction work in progress for ratemaking. In contrast to investor-owned systems, very little of the end-use sales of state/municipal systems and cooperatives is subject to state-level regulation. Publicly owned electric systems have access to relatively less expensive sources of debt capital in comparison with investor-owned systems. In 1984, the average long-term interest rate for investor-owned systems was 9.67 percent in comparison with 7.00 percent, 8.20 percent, and 7.76 percent for state/municipal systems, cooperatives, and Federal projects, respectively. In general, publicly owned utilities are exempt from Federal taxation. However, with the exception of the five Federal power marketing agencies, they are either subject to sub-Federal taxation or make in-lieu-of-tax payments. In 1984, total tax payments attributable to electric operations accounted for 15.41 percent of the total electric operating revenues of investor-owned electric utilities. For state/municipal systems and rural electric cooperatives, the corresponding percentages were 4.89 percent and 2.03 percent, respectively.

1. INTRODUCTION

Electric power in the United States is provided by the electric utility industry and various private sources such as industrial, mine, and railway power plants. This report is limited exclusively to the electric utility industry.

By ownership type, the U.S. electric utility industry consists of (1) investor-owned electric utilities, (2) rural electric cooperatives, (3) Federal power projects, and (4) state/municipal electric systems (state power projects, county power projects, public utility districts, municipally owned electric systems, and joint action agencies). Technically, publicly owned--as opposed to privately owned--electric utilities consist of the latter two ownership types. However, because of their Federal tax-exempt status, relatively less costly sources of debt financing, and preferred access to power produced at Federal dam sites, rural electric cooperatives are included as part of the publicly owned segment of the U.S. electric utility industry for purposes of this study. Federal power projects include the Tennessee Valley Authority, a corporation owned by the Federal government, and five Federal Power Marketing Agencies and their associated power supply sources: (1) the Bonneville Power Administration (as part of the Columbia River Power System), (2) the Alaska Power Administration, (3) the Western Area Power Administration, (4) the Southwestern Power Administration (as part of the Southwestern Federal Power System), and (5) the Southeastern Power Administration (as part of the Southeastern Federal Power Program).

This report addresses areas that differentiate investor-owned electric utilities and publicly owned electric utilities. Regulatory issues and financial performance are the two broad areas addressed. Regulatory issues include (1) different degrees of Federal and state economic regulation across ownership types; (2) differences in exposure to Federal, state, and local taxation; (3) depreciation policy; and (4) the treatment of construction work in progress for ratemaking. The analysis is a major extension of an earlier study conducted on public power [Hill and Tepel (1985)]. The earlier study was conducted in the context of providing recommendations for modeling the U.S. electric utility industry on the basis of ownership type.

The remainder of the report is divided into four chapters. Chapter 2 provides a background on public power. It includes a description of each of the ownership types; a statistical comparison of (1) generating capacity as of December 31, 1984, (2) sales by Federal region in 1984, and (3) average price per kilowatt-hour of sales in 1984; and a discussion of data sources for each of the four ownership types.

Chapter 3 addresses pricing, regulation, control, and financial issues by ownership type. The discussion of regulation also includes the Federal Energy Regulatory Commission's jurisdiction over wholesale electric rates, wheeling arrangements, and private hydroelectric licensing. Financial issues are depreciation policy, taxation, and the treatment of construction work in progress.

Chapter 4 discusses the sources of capital for each of the ownership types and presents a statistical comparison of the financial performance of privately and publicly owned utilities over the 1979-1984 period. Statistical comparisons of operating results on a percentage of revenues and unit sales basis, interest coverage, effective cost of debt, and return on equity are included in the chapter.

Chapter 5 presents a synthesis of the major conclusions drawn from Chapters 2 through 4.

2. AN OVERVIEW OF PUBLIC POWER IN THE UNITED STATES

2.1. BACKGROUND ON PUBLIC POWER

Public ownership of electric power facilities has long been a part of the U.S. electric utility industry. The first publicly owned system dates back to 1881. For a variety of reasons, the growth of public power has proliferated since that time. Included among the reasons for the growth are development of navigable waterways, flood prevention, provision of water for irrigation, access to relatively less expensive sources of power, and the electrification of rural areas.

2.1.1. State/Municipal Electric Systems

As of December 31, 1984, there were 2,254 state/municipal electric systems in the United States [American Public Power Association (1986)].[1] Of that total, 57 were joint action agencies and the remainder were public utility districts and county, municipal, and state systems. In 1984, the 2,254 electric systems accounted for 14.5 percent of the total end-use sales of the industry.

For the most part, state-level participation in electric power activity is the result of the need to distribute power generated at either Federally financed or state-financed water projects. For example, the New York Power Authority (formerly the Power Authority of the State of New York), the largest state/municipal electric system in the United States in 1984 in terms of sales, was created in 1931 to distribute

[1]The Energy Information Administration compiles annual operating and administrative data for both publicly and privately owned utilities using EIA Form-861, entitled "Annual Electric Utility Report." The operating data includes the sources and disposition of electrical energy. The compilation encompasses nearly 3,300 public and private electric systems.

power produced from the St. Lawrence River Project and, at present, produces power from the Niagra River. Similarly, the South Carolina Public Service Authority (originally the Santee-Cooper Hydroelectric and Navigation Project and, more recently, simply Santee Cooper) was created in 1934 to construct and operate the Santee-Cooper hydroelectric project. Besides producing and selling electric power, the project involved development of the Santee, Cooper, and Congaree Rivers for marine commerce, land reforestation, and reclamation of flooded lands.

Other states with large public agencies include Texas (Lower Colorado River Authority), Oklahoma (Grand River Dam Authority), and Arizona (Arizona Power Authority). The Lower Colorado River Authority was created by the state of Texas in 1934 to control waters of the Colorado River for irrigation, forest development, and production of electric energy. The Grand River Dam Authority was created by the state of Oklahoma in 1935. Presently, it sells electricity at wholesale to rural electric cooperatives and municipally owned utilities and, at retail, to industrial users of power.

City or municipally owned systems proliferated during the early years of the U.S. electric utility industry. Most of them were originally constructed in small towns to provide electric service to areas that would not otherwise be serviced. As early as 1921, there were 2,581 municipal systems in existence, but that number dwindled shortly thereafter with the advent of the holding companies' consolidation movement. Today, a large number of municipal systems are located in Federal power regions where they have access to "preference power" produced at Federally financed water projects.

The largest municipally owned electric system serves the city of Los Angeles. In 1984, the utility had more than $1.2 billion of revenues with sales of more than 19.8 billion kilowatt-hours derived from more than $2.6 billion in net electric plant. Other large cities with municipally owned electric utilities include Memphis, San Antonio, Sacramento, Nashville, Seattle, Jacksonville, Tacoma and Austin.

Public power is most prevalent in the state of Nebraska where all of the electric utilities that have primary service areas in the state are publicly owned. The origin of public power in Nebraska is legislation enacted in 1939 that created a Consumers' Public Power District. In the ensuing years, the District purchased private power facilities to the extent that, by 1946, all electric power distribution in the state was provided by publicly owned utilities.

The most recent phenomenon associated with state/municipal electric systems is the formation of Joint Action Agencies (JAAs). JAAs are a manifestation of state-level legislation that allows two or more municipal utilities and other power systems to finance and construct generation and transmission facilities. The reasons for their formation and proliferation include the inability of many public electric systems to meet their load requirements from traditional sources of wholesale power (Federal hydroelectric power, for example) and the need to pool financial resources in constructing central station power plants because of the relatively small size of public systems. As of December 31, 1984, there were 57 JAAs in existence in 31 states that have enacted legislation to allow their formation. The number of participants in JAAs and their generating capacity vary widely. A complete listing of JAAs and the location of their headquarters is provided in Appendix A.

From an overall perspective, the most salient characteristic of the state/municipal segment of the U.S. electric utility industry is the existence of very small power systems. In 1984, for example, the three largest state/municipal electric systems in terms of net investment in electric plant--Salt River Project in Arizona, Los Angeles Department of Water and Power, and the New York Power Authority--accounted for 17.5 percent of the total net investment in electric plant made by all 2,254 state/municipal systems. Adding the fourth and fifth largest--the city of San Antonio and South Carolina Public Service Authority--the top five accounted for more than 25 percent of the total. The ten and 20 largest accounted for 39.7 percent and 53.9 percent of the total, respectively.

With respect to revenues generated from electric operations, the three largest--the city of Los Angeles, the New York Power Authority, and the Puerto Rico Electric Power Authority--accounted for 16.4 percent of the total. The five, ten and 20 largest accounted for 23.1 percent, 33.1 percent and 45.8 percent of the total of all state/municipal systems, respectively.[2]

2.1.2. Rural Electric Cooperatives

The Rural Electrification Administration (REA) was created by Executive Order in May of 1935. Its primary purpose was to act as a credit agency to advance interest-bearing loans to public or private institu-

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[2]The percentages for the largest state/municipal electric systems in terms of net investment and revenues were computed from data contained in American Public Power Association (1986).

tions willing to construct power lines in rural areas. The agency was authorized by statute in May of 1936 and became part of the Department of Agriculture in 1939. Usually formed by groups of farmers, rural electric cooperatives (RECs) were responsible for increasing the percentage of U.S. farms with electric service from 11.6 percent in 1935 to nearly 99 percent in 1982.

The original intent of the legislation enacted to create REA was to form a lending agency that would ensure the availability of capital for the construction of electric distribution systems in remote areas. Because of low population density in many parts of the country (relatively low number of customers per distribution-mile), financial incentives did not exist for investor-owned utilities to service remote areas. A credit agency was created to provide funding at reasonable rates to groups of farmers or other institutions who desired central station electric service.

Under the original formulation, RECs were to obtain wholesale power from federal dams and/or other private and public local suppliers. It was envisioned that REA would make loans for generation and transmission facilities (G&T loans) only if cooperatives did not have access to supplies of wholesale power or, alternatively, if the estimated cost of generating their own wholesale power was less than their present sources. In 1961, restrictions on G&T loans were relaxed by REA. G&T loans now were advanced where the effectiveness and security of a cooperative were at stake.

At December 31, 1984, there were 992 borrowers who had loans outstanding with REA, 111 former borrowers who had repaid their loans in full, and two borrowers who had their loans foreclosed. Of the 992 active borrowers, 929 were distribution-type borrowers and 63 were G&T or power supply borrowers. Only 869 of the distribution-type borrowers were technically cooperatives. The remainder were public power districts (44), other publicly owned utilities (13), and investor-owned utilities (3) that were advanced loans to provide electric service in remote areas. Of the 63 active G&T borrowers, 58 were cooperatives, two were public power districts, two were publicly owned utilities, and one was an investor-owned utility. In 1984, cooperatives accounted for 6.9 percent of the total end-use sales in the U.S. electric utility industry.

Three characteristics distinguish rural electric cooperatives from investor-owned utilities: (1) they are priority purchasers of relatively less expensive wholesale power generated at Federal water project sites; (2) they are, in general, exempt from Federal taxation; and (3) they have access to relatively less costly sources of long-term financing. Their exemption from Federal taxation is attributable to Section 501 of the Internal Revenue Code. Under provisions of that section of the Code, RECs are not subject to federal profits taxes if they generate at least 85 percent of their revenue from electricity sales to members of the cooperative. A thorough discussion of the long-term financing sources for RECs is presented in Chapter 4.

2.1.3. Federal Power Projects

The Federal government has long been a part of the U.S. electric utility industry. Their participation proliferated as a result of the New Deal in the 1930's. Initially, its entry into the electric power industry was indirect. Dams originally constructed for purposes of providing navigable waters, providing water for irrigation, preventing floods, or storing water for municipalities were also sources of electric power. Presently, all of the power produced at Federal dam sites is sold at wholesale or retail by five Federal Power Marketing Agencies (PMAs) and the Tennessee Valley Authority (TVA). PMAs include the Bonneville Power Administration, the Western Area Power Administration, the Southwestern Power Administration, the Southeastern Power Administration, and the Alaska Power Administration. TVA is a separate corporation within the Federal government. Figure 2.1 provides the service areas for the five PMAs and TVA.

Since the majority of sales of Federally owned projects are made at wholesale, Federal power projects account for a small portion of total end-use sales in the electric utility industry. In 1984, for example, Federal projects' portion of total end-use sales in the industry was 2.6 percent.

The Bonneville Power Administration (BPA) was created in 1937 with enactment of the Bonneville Power Act. Its original purpose was to construct a transmission system to market power generated at the Bonneville Dam. Today, BPA acts as the power marketing agent for 30 Federal dams operated by the Department of Interior's Bureau of Reclamation and the Department of Defense's Army Corps of Engineers. Together, BPA and the Pacific Northwest generating facilities of the Corps of Engineers and the Bureau of Reclamation constitute the Federal Columbia River Power System (FCRPS). As depicted in Figure 2.1, Bonneville markets power in

Figure 2.1
Federal Power Regions

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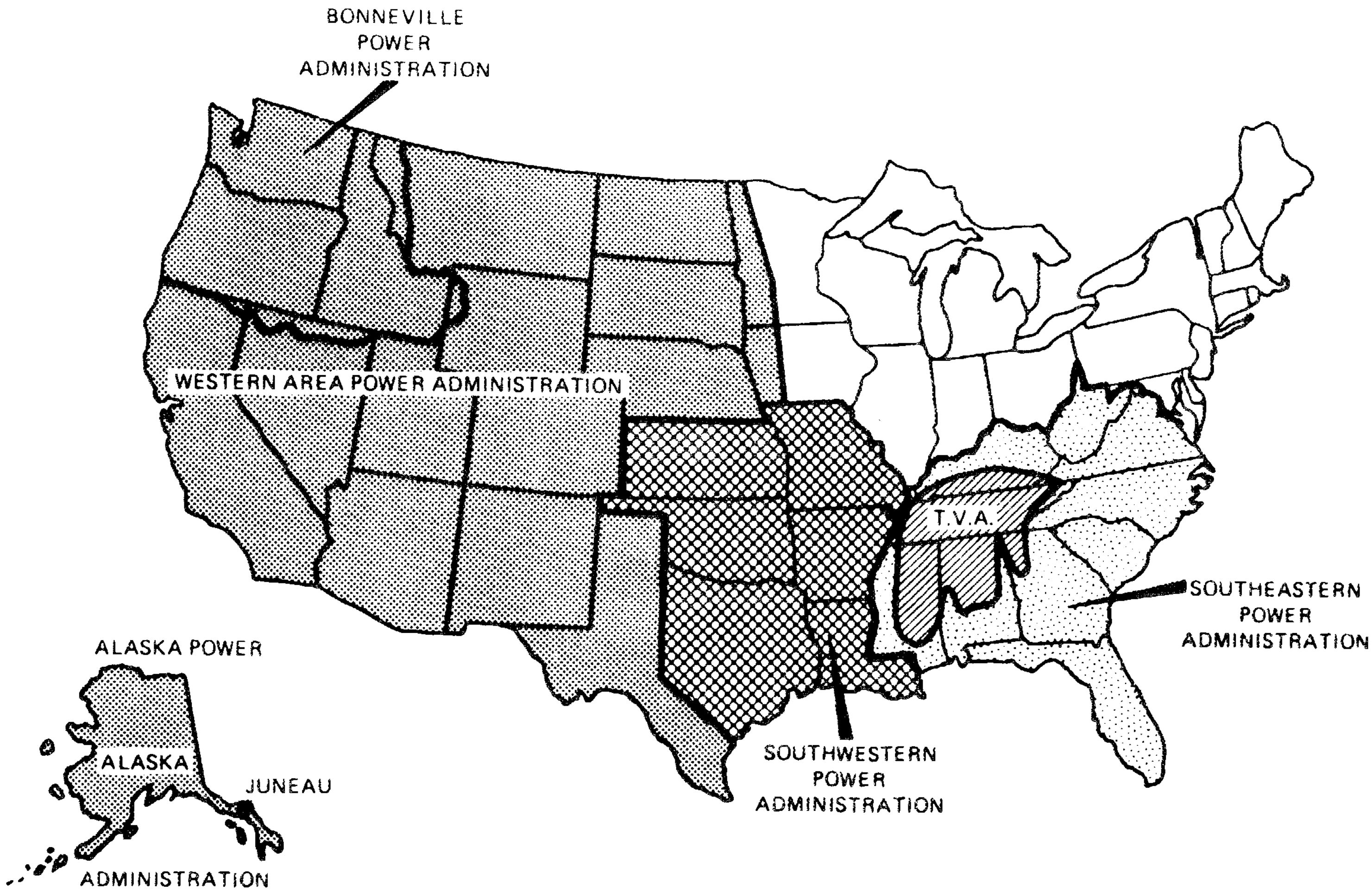

at least a portion of the states of Washington, Oregon, Idaho, Nevada, Wyoming, and Utah.

The Western Area Power Administration (WAPA) was created in 1977 with enactment of the Department of Energy Organization Act. It is responsible for marketing power in 15 states (see Figure 2.1). WAPA markets power generated by the Bureau of Reclamation, the U.S. Army Corps of Engineers, and the International Boundary and Water Commission at 49 dam sites. Additionally, WAPA markets the Federal government's portion of power generated at the Navajo coal-fired unit in Arizona and at a Wyoming wind farm.

The Southwestern Power Administration (SWPA) was created in 1943 and originally placed under the jurisdiction of the U.S. Department of Interior. It was placed under the Department of Energy in 1977 when that agency was formed. SWPA is responsible for marketing power generated by the U.S. Army Corps of Engineers at 23 dam sites in the states of Oklahoma, Missouri, Arkansas, and Texas. The power is sold in Arkansas, Missouri, Louisiana, Kansas, Texas, and Oklahoma. Together, Southwestern and the Corps comprise the Southwestern Federal Power System (SFPS).

The Southeastern Power Administration (SEPA) was created in 1950 under the jurisdiction of the Department of Interior. It was placed under the jurisdiction of the Department of Energy in 1977. SEPA's role is to market power generated at 21 dam sites by the Corps of Engineers in 10 states (see Figure 2.1). SEPA and the Corps combined comprise the Southeastern Federal Power Program (SFPP). Unlike the other PMAs, SEPA does not own a transmission system but relies on the existing grid in the southeast to transmit power generated at the dam sites.

The Alaska Power Administration (APA) was formed as a part of the Department of Interior in 1967. Like the other PMAs, it was placed under the jurisdiction of the Department of Energy in 1977. APA's function is to market the power generated from two hydroelectric projects in Alaska: the Eklutna Project and the Snettisham Project.

The Tennessee Valley Authority (TVA) was created as a Federal government corporation in 1933 for multiple purposes. It was created primarily for flood control and development in the Tennessee Valley area and only secondarily as a power agency. By its enabling legislation, TVA's electric power program is operated on a self-supporting basis and, because of this, is not funded primarily by Congressional appropriations. The enabling legislation also permits TVA to control retail rates charged by its power purchasers even though TVA is primarily a wholesale power supplier.

2.2. STATISTICAL OVERVIEW: CAPACITY, SALES, AND AVERAGE PRICE

Table 2.1 provides the total generating capacity of the U.S. electric utility industry as of December 31, 1984 by ownership type and prime mover. The investor-owned segment of the industry accounted for more than three-fourths (76.6 percent) of total generating capacity in 1984. While state/municipal systems accounted for only a little more than 10 percent of total capacity, their ownership interest in internal combustion systems accounted for more than 60 percent of the 4,841 megawatts (MW) of capacity in existence at the end of 1984. Similarly, while Federal projects accounted for less than 10 percent of total

Table 2.1
Total Generating Capacity
U.S. Electric Utility Industry
By Ownership Type and Prime Mover,
December 31, 1984

(Capacity in Megawatts)

Prime Mover	Investor-Owned Utilities	State/ Municipal Systems	Rural Electric Coops	Federal Power Projects	Total
Conventional Steam:					
Amount	429,047	42,969	24,278	20,244	516,537
%	83.1	8.3	4.7	3.9	100.0
Nuclear:					
Amount	58,380	6,157	50	5,897	70,484
%	82.8	8.7	.1	8.4	100.0
Internal Combustion:					
Amount	1,306	3,188	330	17	4,841
%	27.0	65.9	6.8	.4	100.0
Hydroelectric:					
Amount	26,127	17,243	81	37,139	80,590
%	32.4	21.4	.1	46.1	100.0
Wind/Solar:					
Amount	3	1	0	7	11
%	27.3	9.1	-	63.6	100.0
Total Industry:					
Amount	514,863	69,558	24,738	63,304	672,462
%	76.6	10.3	3.7	9.4	100.0

SOURCE: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1984.

capacity in 1984, they accounted for nearly 50 percent of total hydroelectric capacity.

The most marked growth in generating capacity during the course of the past two decades has been in rural electric cooperative-owned systems. Total generating capacity in the U.S. electric utility increased a little more than three-fold from 1964 to 1984--from 222,285 MW of installed capacity in 1964 to 672,462 MW in 1984. For RECs, the corresponding increase has been more than twelve-fold--from 2,017 MW in 1964 to 24,738 in 1984. As discussed above, the large increase in REC capacity is a manifestation of relaxed lending policies by REA for generation and transmission capacity.

Table 2.2 presents a summary of total end-use sales in the U.S. electricity industry by ownership type and federal region for 1984.[3] Figure 2.2 provides a map of the ten Federal regions to facilitate understanding of Table 2.2.

Table 2.2 shows that the investor-owned segment of the industry accounted for 76.0 percent of total end-use sales in 1984. The percentage is consistent with their ownership of capacity presented in Table 2.1.

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[3]The data in Table 2.2 is consistent with that reported in Edison Electric Institute's (EEI's) 1984 Statistical Yearbook of the Electric Utility Industry. However, the data is considered preliminary and subject to revision for presentation in later yearbooks. Moreover, wholesale sales made by TVA to firm power municipal and cooperative customers in its seven states of operation in the Southeast (Virginia, North Carolina, Georgia, Kentucky, Tennessee, Alabama, and Mississippi) that are considered federal power sales by EEI have been reclassified as state/municipal and cooperative sales in Table 2.2. With the exception of Virginia which is in Federal Region 3, all of the TVA-supported states are in Federal Region 4. The total amount of sales made by TVA to state/municipal systems and cooperatives in those seven states in 1984 was 76,859 gWh, composed of 55,929 gWh to municipally owned utilities and 20,930 gWh to cooperatives.

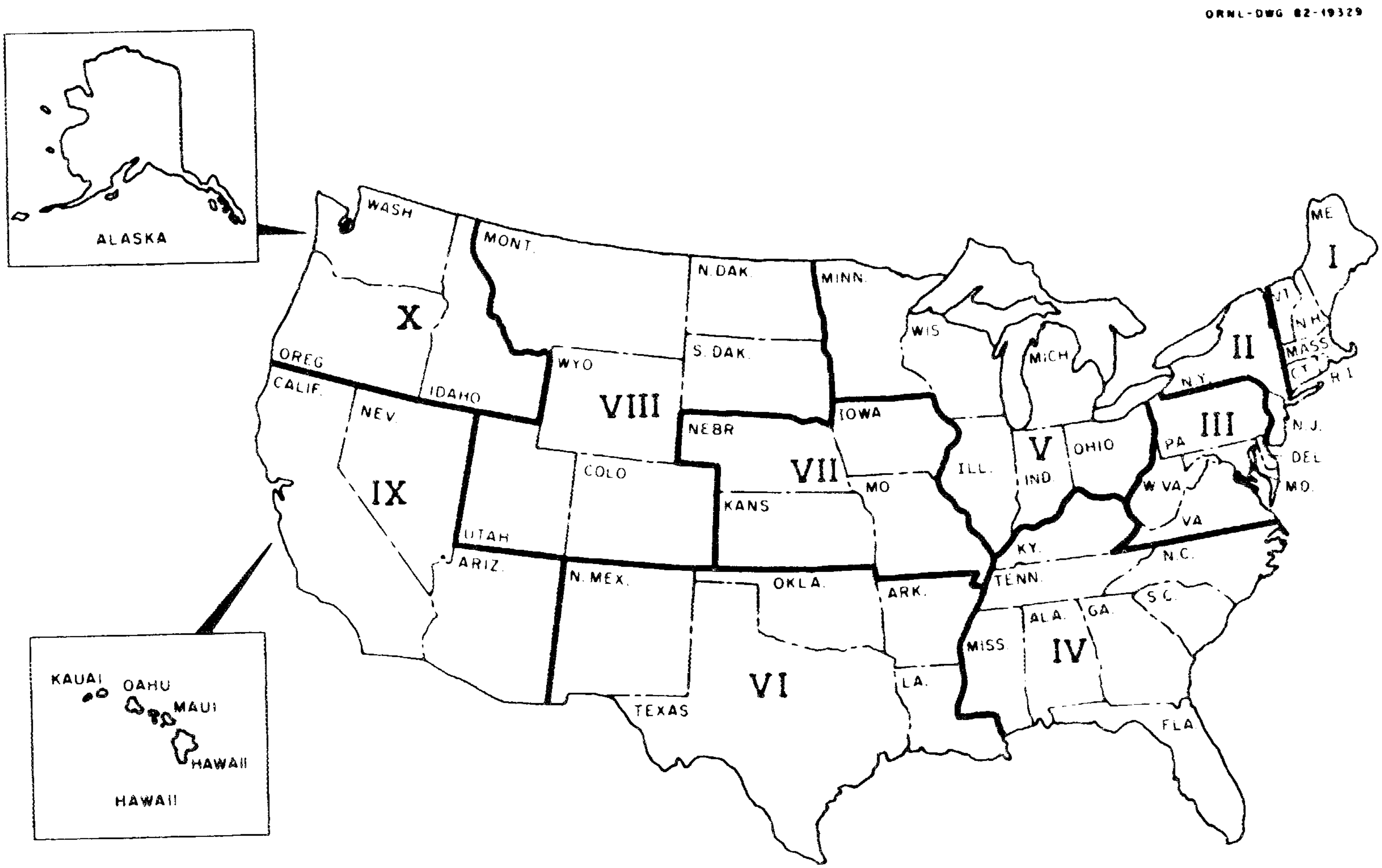
Table 2.2
Total End-Use Electricity Sales
U.S. Electric Utility Industry
Amount and Percent Composition by Ownership Type and Federal Region
1984

(Amounts in Gigawatt-Hours)

Federal Region	Investor-Owned		State/Municipal		Cooperatives		Federal Projects		Regional Total	
	Amount	%	Amount	%	Amount	%	Amount	%	Amount	%
1	78,792.7	91.3	6,887.3	8.0	631.3	0.7	0.0	0.0	86,311.4	100.0
2	146,973.0	89.7	16,753.0	10.2	196.0	0.1	0.0	0.0	163,922.1	100.0
3	218,240.1	94.7	5,155.4	2.2	7,126.6	3.1	0.0	0.0	230,522.2	100.0
4	288,885.0	59.8	103,729.7	21.5	64,528.7	13.4	25,994.0	5.4	483,137.5	100.0
5	383,152.9	88.9	27,168.8	6.3	20,597.3	4.8	41.6	0.0	430,960.6	100.0
6	279,963.9	81.3	34,151.1	9.9	29,955.5	8.7	215.8	0.1	344,286.4	100.0
7	68,786.9	62.6	29,197.7	26.6	11,709.9	10.7	141.6	0.1	109,836.1	100.0
8	47,336.7	65.6	6,866.8	9.5	14,601.0	20.2	3,310.7	4.6	72,115.2	100.0
9	164,207.0	72.8	53,772.6	23.8	2,007.4	0.9	5,586.5	2.5	225,573.4	100.0
10	60,519.0	43.6	47,219.6	34.0	7,046.7	5.1	24,081.8	17.3	138,867.1	100.0
US Total	1,736,857.3	76.0	330,902.1	14.5	158,400.5	6.9	59,372.0	2.6	2,285,531.8	100.0

SOURCE: Compiled from data provided by the Edison Electric Institute.

Figure 2.2
The Ten DOE Regions



On a regional basis, investor-owned utilities accounted for the largest portion of end-use sales in regions 1, 2, and 3 of the Northeast where Federal power sales are non-existent. Similarly, the investor-owned portion is large in regions 5 and 6 where Federal power sold at wholesale to preference customers--state/municipal systems and rural electric cooperatives--is a relatively small portion of power sold in those regions. The relatively small percentage of end-use sales by the investor-owned segment--and relatively large percentage accounted for by state/municipal systems--in region 7 is attributable, in large part, to the state of Nebraska where nearly all end-use customers are served by public power sources.

The investor-owned segment's share of end-use sales is lowest in the eight states that comprise region 4 and the four states that comprise region 10. As indicated by the share of Federal power sold in both of these regions, regions 4 and 10 have the highest concentration of Federal power production. TVA dominates in region 4 and BPA markets power produced at Federal dam sites in region 10.

The relatively large portion (10.2 percent) of end-use sales accounted for by state/municipal systems in region 2 is attributable for the most part to large-volume, industrial sales made by the New York Power Authority. The relatively large percentage of end-use sales made by state/municipal systems in regions 4, 9, and 10 can be explained by the abundance of Federal and sub-Federal hydroelectric power produced in these regions. Publicly owned utilities are given preference for purchase of wholesale produced at federal dams.

The concentration of sales made by cooperatives lies in the relatively less densely populated regions of the country's midsection.

Table 2.3 provides the average sectoral price of electricity in the U.S. electric utility industry by class of service, ownership type, and Federal region in 1984. For ease of presentation, state/municipal systems, rural electric cooperatives, and federal projects have been combined as publicly owned utilities in Table 2.3. The prices presented in the table were calculated by dividing total end-use revenue by total end-use sales for each of the ownership types across Federal regions.

Table 2.3 shows that, for the United States in the aggregate across all classes of service, the average price charged by publicly owned systems was 1.25 cents/kWh lower than investor-owned systems. The difference was 1.41, 1.44, 1.00, and 1.58 cents/kWh for residential, commercial, industrial, and other sales, respectively. The largest discrepancy was in region 2 where, in the aggregate, the average price of electricity for publicly owned systems was 5.04 cents/kWh lower than that of investor-owned systems. The difference is attributable to the New York Power Authority which markets relatively less expensive hydroelectric power at retail to large-volume users and at wholesale to publicly owned systems in the region.

A number of factors account for the differences in the average price of electricity across both Federal regions and ownership types presented in Table 2.3. Given an ownership type, population density, generation mix and, holding the mix constant, the price of coal, oil, and natural gas are included among the factors that contribute to price differences across regions of the country. Across ownership types, dif-

Table 2.3
Average End-Use Price of Electricity
U.S. Electric Utility Industry
By Class of Service, Ownership Type, and Federal Region
1984

(In Cents per Kilowatt-Hour)

Federal Region	Residential		Commercial		Industrial		Other*		Total**	
	IOU	POU	IOU	POU	IOU	POU	IOU	POU	IOU	POU
1	9.37	8.60	8.88	8.80	7.06	7.21	11.25	8.81	8.59	8.16
2	10.83	4.33	10.39	3.79	7.05	1.96	10.01	7.50	9.60	4.56
3	7.24	7.12	6.77	6.56	4.99	4.59	6.47	7.21	6.22	6.55
4	7.12	5.99	6.57	5.95	4.57	4.56	4.36	5.90	5.98	5.37
5	7.49	6.73	7.04	6.25	4.72	4.56	6.41	4.95	6.09	6.06
6	7.07	7.31	6.42	6.82	4.64	5.49	5.49	4.31	5.81	6.67
7	6.92	6.42	6.23	6.22	4.61	4.40	7.39	5.15	5.98	5.88
8	6.60	5.78	5.81	5.82	3.78	3.81	6.16	3.03	5.35	5.07
9	7.65	6.25	8.32	6.07	7.20	4.63	9.38	2.64	7.78	5.25
10	4.45	3.60	4.69	3.51	3.40	2.32	9.92	2.35	4.26	2.90
US Total	7.53	6.12	7.33	5.89	5.07	4.07	6.27	4.69	6.53	5.28

SOURCE: Compiled from data provided by the Edison Electric Institute.

*The category Other includes sales (1) for street and highway lighting, (2) to public authorities, (3) to railroads and railways, and (4) for interdepartmental uses.

**The total is a weighted average of all sectoral sales.

IOU--Investor-owned electric utilities.
POU--Publicly owned electric utilities (includes state/municipal electric systems, rural electric cooperatives, and federal power projects).

ferences in the average price of electricity are attributable to differential regulation and pricing strategies, exemption from Federal taxation, preferential sources of relatively low-cost power, and access to relatively less costly long-term financing sources. These issues are the subject matter of the next two chapters.

2.3. DATA SOURCES FOR THE U.S. ELECTRIC UTILITY INDUSTRY

The most statistically comprehensive source of annually published information on the U.S. electric utility industry is Edison Electric Institute's (EEI) publication Statistical Yearbook of the Electric Utility Industry. The publication includes a wide array of data on generating capacity, total generation, generation by fuel type, revenues, sales, and customers in the aggregate and at the state level. Unfortunately, the only variables for which information is presented on a disaggregated basis by ownership type (IOUs, state/municipal systems, RECs, and Federal power projects) in the Yearbook are capacity and generation. For all other variables contained in the report, the data are segregated between the aggregate industry (all ownership types combined) and the investor-owned segment only.

Financial information in the Statistical Yearbook is provided only for the investor-owned segment of the industry. EEI does not assemble financial data for state/municipal systems, RECs, and Federal power projects. Financial information for IOUs includes balance sheets, income statements, detail of taxes and O&M expenses, capitalization, and long-term financing.

Other governmental and private organizations collect information on the publicly owned segment of the industry in varying levels of detail.

They include the Energy Information Administration, the American Public Power Association, and the Rural Electrification Administration. The nature of available data is discussed by ownership type.

2.3.1. State/Municipal Electric Systems

As noted above, there were more than 2,200 state/municipal electric systems in operation during 1984. The only statistically comprehensive public source of information on the financial and operating performance of those utilities is provided by the Energy Information Administration (EIA) in its annual report entitled Financial Statistics of Selected Electric Utilities (hereafter, Statistics). Unfortunately, the EIA report does not incorporate the universe of state and municipal systems but, currently, only a majority of the largest systems. In the 1984 Statistics, for example, the 162 utilities that comprised the report accounted for a little more than 52 percent of the total end-use sales volume of all state/municipal electric systems.[4]

Prior to 1977, coverage of state/municipal systems in the Statistics was much broader than in recent years. In 1974, for example, 511 utilities were incorporated in the report. However, because of statistical inconsistency for yearly comparisons, EIA's presentation in the 1977 Statistics included only "major municipals" (those utilities with more than $5 million in revenues)--restated back to 1974 for comparative purposes--and the practice has been carried over to the present. Moreover, beginning in 1982, financial information on individual utilities

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[4]Total end-use sales for the 162 utilities were 173,099.3 gWh in 1984 [Energy Information Administration (1986)]. Total end-use sales for all state/municipal systems were 330,902.1 gWh in 1984 (Table 2.2).

that comprise state/municipal electric systems were not presented. Only aggregate data is presented.[5]

A significant problem arises when the aggregate information provided by EIA in the Statistics is to be used for comparison over time or with different ownership types. Even though the systems that are incorporated in the report have remained virtually constant since 1977 (and restated back to 1974), the aggregate results are not consolidated in the technical accounting sense. Therefore, the aggregate results for any one year include double-counting of some activity. For example, if the inter-company sales made between the 162 companies that comprise the 1984 Statistics were not eliminated, revenues and purchased power for the 162 companies would be overstated. Fortunately, individual annual reports for the companies are on file at the Federal Energy Regulatory Commission in detail sufficient to identify and eliminate transactions between the 162 companies. For comparative purposes in Chapter 4, the sales elimination was made for the years 1979 through 1984.[6]

In addition to the Statistics compiled by EIA, the American Public Power Association (APPA), in its annual publication Public Power Directory, provides some summary information on the operating results of state and local systems in addition to a listing of those systems. However, it does not provide the balance sheet and income statement detail

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[5]A computer printout of the 162 individual state/municipal systems that comprise the aggregate is available from EIA upon request.

[6]Specifically, the dollar value of wholesale sales among the 162 utilities in the sample were tabulated and used to reduce both revenues and production expenses of state/municipal systems. Similarly, the total amount of wholesale electricity sales among the 162 utilities was subtracted from the total sales of those utilities.

required for a comprehensive analysis of the operating performance of publicly owned systems. The basis for data in the Public Power Directory is an annual Survey of Publicly Owned Electric Systems conducted by APPA. The survey solicits information on sectoral activity (total customers, total volume, and total revenues), net investment, generation, and installed generating capacity.

2.3.2. Rural Electric Cooperatives

Cooperatives with outstanding loans from the Rural Electrification Administration are required to submit annual reports to REA. The information is summarized and published annually in two volumes: Statistical Report, Rural Electric Borrowers and Annual Report of Energy Purchased by REA Borrowers. The former report presents aggregate and individual cooperative financial statements (income statement, balance sheet), operating statistics, and a detailed presentation of the outstanding loans of the cooperatives. The latter report, as the title implies, presents a detailed account of purchases and wholesale sales of the cooperatives.

2.3.3. Federal Power Projects

Up until 1980, individual Federal power projects were required to provide the Federal Energy Regulatory Commission (FERC) with an annual report similar in format to those submitted by state/municipal systems. The information was presented in the Statistics of Publicly Owned Electric Utilities in the United States on an aggregate basis and by individual federal project. However, FERC Order 146, issued in May of 1981, eliminated the requirement for Federal power projects to report to FERC.

Beginning in 1982, EIA published partial information on Federal power projects in the <u>Statistics</u>. Presently, the only comprehensive published source of information on Federal power projects is their individual annual reports submitted to the Secretary of the Department of Energy. Unfortunately, they are not presented in the format of EIA-412 (formerly Form 1-M), the reporting form used by state/municipal systems, but they do contain a sufficient level of detail on the Federal projects' operating and financial performance.

Federal power project annual reports can be obtained for the Tennessee Valley Authority, the Southwestern Federal Power System, the Southeastern Federal Power Program, the Columbia River Power System, the Alaska Power Administration, and the Western Area Power Administration. Data for the Southwestern Federal Power System reflect a consolidated report for the Southwestern Power Administration--the Federal power marketing agency--and hydroelectric projects under the jurisdiction of the U.S. Army Corps of Engineers (Corps). Similarly, the Southeastern Federal Power Program represents the consolidated results of the Southeastern Power Administration and the Corps, while the results for the Columbia River Power System reflect the consolidation of the Bonneville Power Administration, the Corps, and the U.S. Bureau of Reclamation in the Northwest. Up until 1980, the Western Area Power Administration provided a consolidated report for its power marketing operations and the hydroelectric operations of the Corps and the Water and Power Resources Service. As of 1980, however, Western's annual report only includes the financial results for its power marketing operations and not the hydroelectric operating results.

3. REGULATION, PRICING, AND FINANCIAL ISSUES IN THE U.S. ELECTRIC UTILITY INDUSTRY BY OWNERSHIP TYPE

3.1. INTRODUCTION

The statistical comparison in the previous chapter masks the complex interrelationships of the various ownership types in the U.S. electric utility industry. Consider Figure 3.1 which presents a schematic representation of the operation of the U.S. electric utility industry by ownership type. The characterization of the industry in Figure 3.1 shows (1) a matrix of generating unit ownership by ownership type under the heading Production; (2) wholesale sales and vertically integrated unit system sales under the heading Wholesale/System Sales; and (3) distribution of electricity to ultimate consumers under the Distribution and End-Use headings. The figure does not characterize wheeling arrangements in which a utility may "wheel" or transmit power for another utility (to be discussed below).

Figure 3.1 shows that generating capacity is owned either (1) individually; (2) jointly with utilities of the same ownership type; or (3) jointly with utilities of different ownership types. Reading the production matrix from top down and to the right, investor-owned utilities (IOUs) own generating facilities either individually or in "joint venture" arrangements with other IOUs, state/municipal systems, and rural electric cooperatives (RECs). Similarly, state/municipal systems and RECs individually own production facilities and participate in various joint ownership arrangements among themselves and with IOUs. None of the Federal production facilities are jointly owned with other ownership types. As discussed in the previous chapter, joint action agencies (JAAs) are a relatively recent phenomenon for publicly owned

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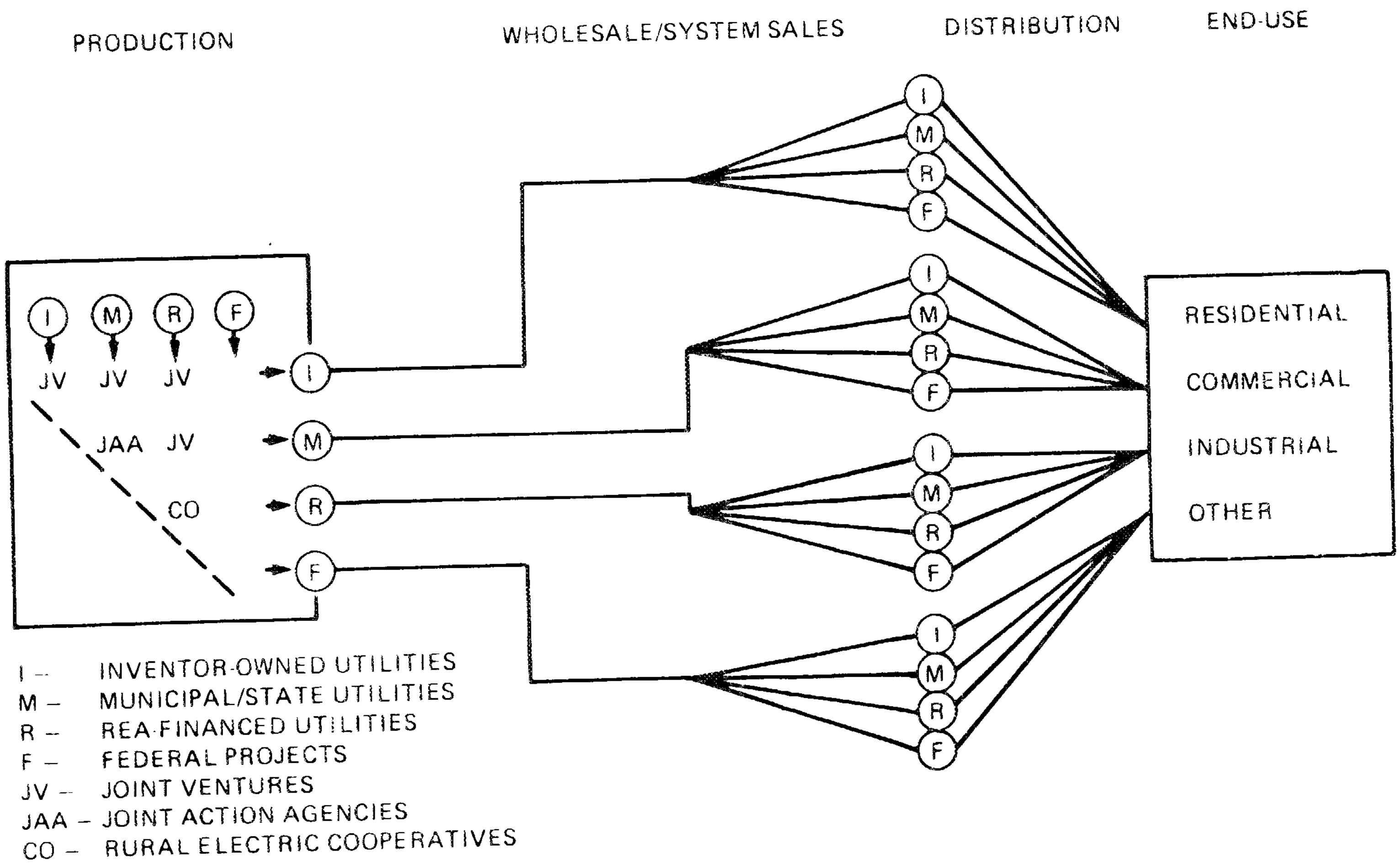
Figure 3.1
Schematic Representation of the U.S. Electric System
By Ownership Type

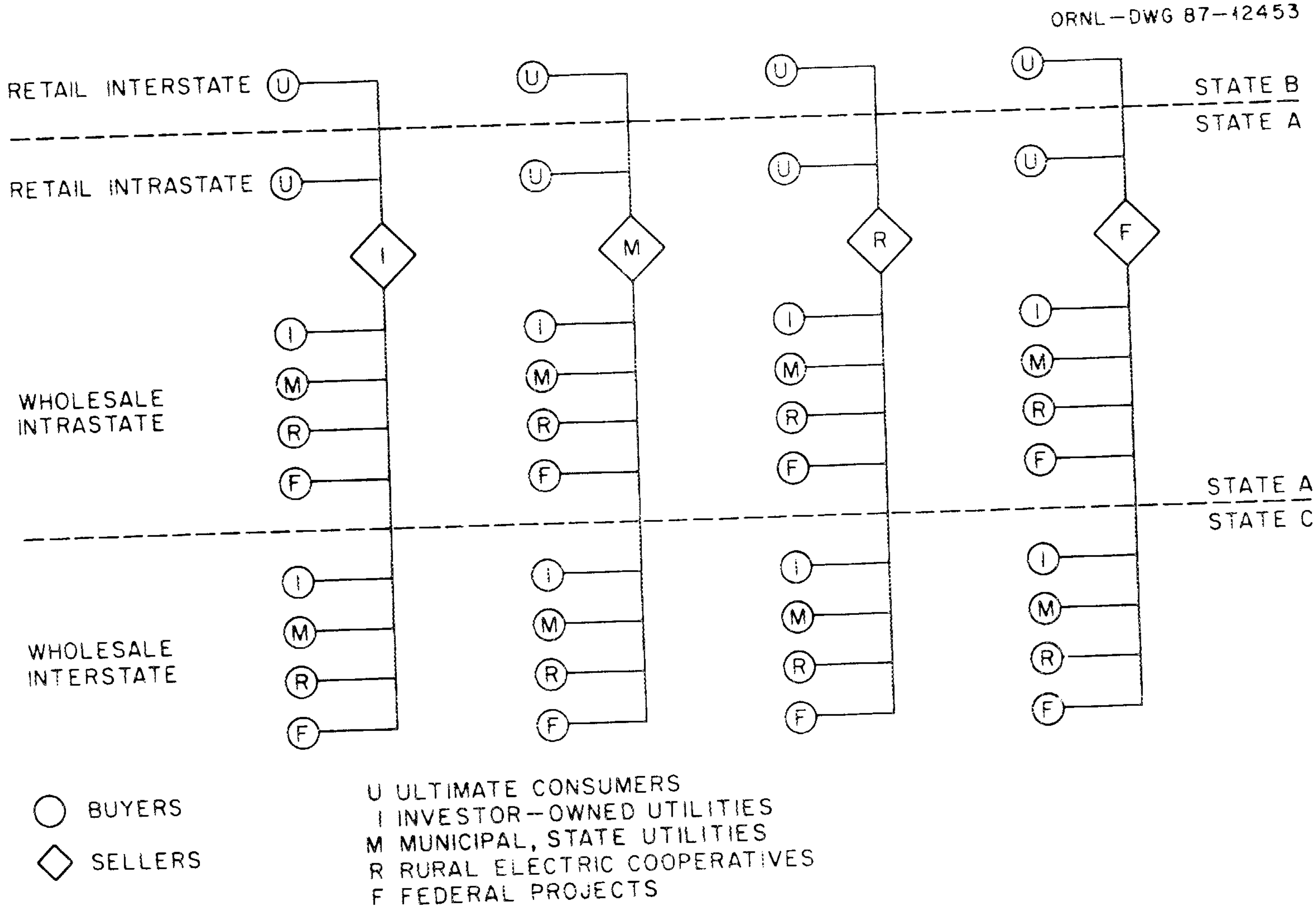


municipal systems that allows two or more municipal utilities and other power systems to finance and construct generation and transmission facilities. A list of the 57 JAAs in existence in 1984 is provided in Appendix A.

The Wholesale/System Sales in Figure 3.1 captures three types of electricity flows: (1) wholesale (or resale) sales between different ownership types; (2) wholesale (or resale) sales between different utilities of the same ownership type; and (3) the flow of electricity through an individual utility's vertically integrated electric system. The characterization of wholesale/system sales in Figure 3.1 underscores the complexity of the U.S. electric system. Besides integrated system sales and sales between utilities of the same ownership type, utilities of each of the ownership types sells, to varying degrees, electricity at wholesale to utilities of each of the other ownership types. The distribution and sale of electricity to ultimate end-users is accomplished by each of the organizational types. However, a large majority of end-use sales made by Federal power projects--five Federal power marketing agencies and the Tennessee Valley Authority--are made to large-volume industrial consumers.

To clarify the types of sales made by individual ownership types and to provide a background for much of the discussion on regulatory issues in the remainder of this chapter, Figure 3.2 provides a schematic representation of all of the possible types of sales that can be made by each of the ownership types. Figure 3.2 shows that each of the ownership types can make both intrastate and interstate sales to ultimate consumers. Additionally, each of the ownership types sells electricity

Figure 3.2
Schematic Representation of U.S. Electricity Sales
By Ownership Type



at wholesale to each of the other ownership types either within an individual state's borders or to utilities outside of their primary state of operation.

Economic regulation of the different types of sales characterized in Figure 3.2 is accomplished by various Federal, state, and local regulatory institutions. They include the Federal Energy Regulatory Commission (FERC); state regulatory authorities; municipal governing bodies or independent municipal electricity boards created by local governing bodies; and, to a lesser extent, the Rural Electrification Administration (REA).

For retail sales, IOUs are regulated by individual state-level authorities in the states in which the utility distributes electricity. For multi-state distributors of electricity to ultimate consumers, rates are subject to review by multiple state regulatory bodies. The sale of electricity for end-use by municipally owned systems is generally under the jurisdiction of either the local governing body or an independent electricity board, elected or appointed to oversee the operations of the publicly owned system. As will be discussed below, state-level regulatory body jurisdiction over the end-use rates of municipally owned systems is not as extensive in comparison with local control of those utilities. Since state power projects are generally organized as state corporations, responsibility for ratemaking rests with the governing bodies of those corporations.

Although more pervasive across states in comparison with municipally owned systems, state-level jurisdiction over the retail rates of cooperatives is not universal. REA has general authority to ensure that

RECs (both distribution borrowers and power supply borrowers) generate sufficient revenue to "cover" their debt service charges. However, REA is not a regulatory body in a technical sense. Although sales to ultimate consumers represent a nominal portion of the sales of Federal power projects, FERC has ultimate rate-setting authority over end-use rates charged by the Federal Power Marketing Agencies--the Bonneville Power Administration, the Alaska Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, and the Western Area Power Administration. The Tennessee Valley Authority is not a marketing agency but was created by a special act of Congress as a government corporation and its retail rates are determined and approved internally.

Jurisdiction over wholesale rates is a little more complicated. FERC has regulatory jurisdiction over (a) interutility sales of power and transmission services provided by investor-owned utilities and (b) wholesale power sales from the five Federal power marketing agencies. The utilities that comprise the Electric Reliability Council of Texas (ERCOT) are an exception. Similar to end-use rates, wholesale rates charged by TVA are established internally. Sales of electricity between two municipally owned systems at wholesale are specifically excluded from Federal jurisdiction by the Federal Power Act of 1935. Sales at wholesale between two cooperatives were excluded from Federal jurisdiction by a 1961 court decision. Other types of wholesale sales depicted in Figure 3.2--an interstate or intrastate sale from a municipally owned system to an investor-owned utility, for example--are subject to varying degrees of state and local control. Regulatory jurisdiction over those sales will be discussed below.

The remaining five sections of this chapter will expand on this broad overview of economic regulatory jurisdiction in the electric utility industry. The next section is devoted to a brief overview of the extent of FERC's regulatory authority--excluding jurisdiction over Federal Power Marketing Agencies (PMAs) which is deferred to the last section of this chapter. The following section discusses the general form of--and specific issues associated with--the economic regulation of investor-owned utilities. The intent of this section is to provide a background for the discussion of the other three ownership types in the ensuing three sections--state/municipal systems, rural electric cooperatives and Federal power projects. For each of these three ownership types, the discussion centers on regulation and pricing, depreciation policy, taxation, and the treatment of Construction Work in Progress (CWIP).

3.2. FEDERAL REGULATION

The predecessor agency of FERC, the Federal Power Commission (FPC), was created with enactment of the Federal Power Act in 1920. The primary purpose of the FPC at that time was to license private hydro-electric power projects on U.S. waters. With enactment of Part II of the Federal Power Act in 1935, the authority of the FPC was broadened to include jurisdiction over wholesale, interstate sales of electricity. Most recently in 1978, the Public Utilities Regulatory Policies Act (PURPA) further broadened the scope of FERC's authority to include interconnection requirements and wheeling between utilities. At present, excluding jurisdiction over the rate-making of PMAs (to be discussed in the last section of this chapter), FERC has three primary regulatory functions: (1) regulation of wholesale electricity rates; (2)

regulation of wheeling arrangements; and (3) licensing of private sector hydroelectric projects.

3.2.1. Wholesale Sales of Electricity

Regulation of wholesale electricity rates includes (a) sales to full requirements and partial requirements utilities and (b) coordination transactions among utilities. A "requirements customer" is a utility that buys power from another utility and its entire load variation (from minimum load to maximum load) is served by the selling utility. A "full requirements customer" is a requirements customer whose entire load (not just its load variation) is serviced by the selling utility, while a "partial requirements customer" may purchase part of its base load from another source. Allowed revenues on sales for "full requirements" and "partial requirements" transactions are based on recouping all operating costs of the selling utility plus a fair return on invested capital (traditional economic regulation).

Regulation of coordination transactions among IOUs is considerably different from regulation of requirements transactions. Generally, three types of transactions are considered: (1) unit sales; (2) other firm sales; and (3) economy sales. "Unit sales" are sales tied to the production of power from a specific plant. These sales can be short-term or long-term, firm or nonfirm. Firm sales represent sales that can be interrupted only in an emergency, while nonfirm sales are those sales which usually can be interrupted at the discretion of the selling utility. An example of a nonfirm sale is a transaction where the owner of the plant (selling utility) would rather use the power produced from its plant for its own operations than sell it at wholesale. The allowable price for firm sales is based on the average cost of producing power from the plant, including capital costs. The allowable rate for nonfirm sales is usually based on split savings or a rate that is the midpoint between the marginal operating costs of the unit and the system costs of the utility which is purchasing the power.

The second type of coordination transaction, "other firm sales," is negotiated between utilities and is usually based on system costs, but the basis is much less rigid than in other types of coordination transactions. The final type of coordination transaction is "economy sales." The rate for this transaction is determined in a manner similar to unit non-firm sales, but, in contrast, the marginal operating costs of both systems are used rather than the costs associated with the operation of only one plant.

3.2.2. Wheeling Arrangements

The second broad area of FERC jurisdiction is the regulation of wheeling arrangements. Concisely, power wheeling is the simultaneous transfer of electric power over transmission facilities owned by a utility that does not own the transmitted electricity. The concept of "simultaneous transfer" limits the wheeling of power to those transactions where the receipt of the power by the wheeling utility on its lines occurs at the same time as the delivery of power to the utility buying the power or another wheeling utility.

Typically, a wheeling transaction requires a contract between the utilities involved in the transaction. A contract for one type of wheeling service can be referred to as a "wheeling arrangement". A wheeling arrangement may be a separate contract but often is part of a larger contract that may contain power sales contracts or contracts for different types of wheeling services. There are approximately 750 wheeling arrangements on file at FERC [see Tepel et al. (1986)].

A wheeling arrangement may be established between two utilities (a bilateral arrangement) or among a number of utilities (a multilateral arrangement). An example of a bilateral arrangement is where a given utility (Utility A) owns a remote generating unit (or a portion of a generating unit under some form of joint ownership arrangement) in another utility's (Utility B) service area. Rather than constructing its own transmission lines from the generating unit, Utility A may contract to have Utility B transport its power on Utility B's transmission network. A multilateral arrangement can occur where two utilities (Utility A and Utility C) want to exchange power but are geographically separate from one another. Again, rather than constructing a transmission network to connect their service areas, they may contract with another utility (Utility B) to transport the power for them across Utility B's transmission system.

Wheeling arrangements usually specify terms and conditions under which the wheeling service will be provided. The terms and conditions can be categorized into five areas: (1) type of transmission service available; (2) compensation methods and rate forms; (3) specific requirements for service; (4) notice and response requirements; and (5) other miscellaneous requirements.

3.2.3. Private Sector Hydroelectric Projects

The third broad area in which FERC has regulatory jurisdiction in the electric utility industry is the licensing of private hydroelectric facilities. Prior to construction of a hydroelectric facility, a license must be obtained from FERC by the utility undertaking the project. If FERC issues the license, its term is 50 years with the possibility of renewal at its termination. As with other electricity sales, if the power generated at the private hydroelectric site is sold at wholesale for resale, FERC has regulatory jurisdiction over the sale. If the power generated at the site is sold to an ultimate user, the appropriate state-level regulatory body has jurisdiction.

3.3. INVESTOR-OWNED ELECTRIC UTILITIES

3.3.1. Rate of Return Regulation

The pricing of electricity by investor-owned utilities (IOUs) is subject to regulatory review. Regulatory constraints are placed at the Federal level by FERC for wholesale sales and wheeling transactions (as discussed above) and at the state level for sales to ultimate customers. The constraints at both levels are manifested in economic or rate-of-return regulation. Since most of the issues involved in economic regulation are the same at both levels, the discussion here will be on state-level regulation of end-use sales.

In a broad sense, there are two aspects to rate-of-return regulation. First, an individual IOU--in concert with the regulatory authority in its state of operation--must determine the level of revenues required to maintain its financial viability. From an accounting and financial standpoint, this activity includes determining the cost of providing electricity and a rate of return that is (1) sufficient to compensate contributors of capital (owners and creditors) for their investment and (2) large enough to attract new capital. The second aspect of economic regulation involves determining the structure of rates charged to individual customer classes--given the overall level of allowed revenues. This aspect of regulation includes such issues as price discrimination, rates of return to individual customer classes, cost allocation, time-of-day pricing, block rates, and the like.

In a very simplistic form, required revenues (RR) for an IOU are determined as follows:

$$RR = OE + D + T + (RB)(ROR), \tag{1}$$

where OE = Operating expenses,
D = Depreciation expense,
T = Tax expense,
RB = Rate base,
ROR = Rate of return.

Under this formulation, a utility is allowed to generate revenues that recover all expenses (OE, D, and T) plus a return on investment in plant that is used for producing, transmitting, and distributing electricity (RB * ROR). The composition of RR shown in equation (1) is somewhat arbitrary because depreciation, taxes, and a return on investment are technically all operating expenses. They are segregated here, however, because of different issues that arise for each of them in ratemaking.

Allowed operating expenses (OE) are those "just and reasonable" expenses incurred in the process of providing electricity. Expenses not applicable to providing electricity or expenses deemed "unreasonable" or "unjust" are considered "below-the-line" other deductions. Therefore, they are not allowed to be recouped from ratepayers but are charged directly to the owners of the utility.

Categorically, operating expenses include production expenses (including the cost of purchased power and fuel costs), transmission expenses, distribution expenses, customer account expenses, sales and informational expenses, and administrative and general expenses. The categories are further segregated between operating expenses and maintenance expenses. The determination of allowable operating expenses for ratemaking purposes is not consistent across state regulatory bodies. For example, promotional advertising expenditures--as opposed to those that advocate conservation or public awareness of issues--are closely scrutinized and the amount included or excluded from allowable expenses for ratemaking purposes is limited and varies from one jurisdiction to another.

Although depreciation expense (D) does not represent a direct cash outlay by a utility, it is nevertheless included as a cost of providing electricity because it reimburses the owners for the (estimated) amount of plant and equipment used in the process of producing, transmitting, and distributing electricity. The amount of depreciation charged to operations for any period is a function of the asset's original cost, its estimated salvage value, its useful life, and the method used to distribute the cost over its useful life. For financial accounting purposes (as opposed to tax accounting which is discussed below), the method for distributing the cost over the useful life of the asset is usually the straight-line method. That is, the total cost of an asset or class of property is recouped in equal annual charges over the asset's useful life.

An alternative to straight-line depreciation is the sinking fund. Under this approach to calculating depreciation, a reserve is established and equal charges are made to it each period. The annual charges are less than under the straight-line approach because it is assumed that the annual charges are invested and, therefore, interest is earned. For any asset with a given cost (including salvage value and service life), the two methods result in the same amount of nominal charges over the depreciable life of the asset.

An issue related to depreciation accounting that has attracted increasing attention in recent years involves the treatment of decommissioning costs of nuclear reactors. For non-nuclear plant and equipment, an asset's depreciable base--or, alternatively, the amount that is to be included as an operating expense over the asset's useful life--is the actual cost of the asset less the estimated amount that the utility can obtain for it after its usefulness has expired (salvage value). For nuclear reactors, the salvage value is, in general, negative because of the large amount of expenditures required to "decommission" the reactor. The process of decommissioning involves, among other activities, the disposal of radioactive waste at the reactor site.

One of the methods used to account for decommissioning is "negative net salvage." That is, the depreciable base of the reactor is the sum of its original cost plus the (estimated) cost of decommissioning the reactor. In the context of economic regulation, current ratepayers are paying for the total cost of a nuclear program (the original cost plus decommissioning) because required revenues for the utility during the useful life of the reactor include an annual charge for decommissioning.

It is assumed that the individual utility with a nuclear program will "save" the annual decommissioning charges for use at the actual decommissioning.

Recognizing that the annual depreciation charge for decommissioning does not necessarily guarantee that the funds to decommission a plant will be available after its useful life has expired or, perhaps more importantly, that a premature decommissioning of a nuclear reactor may be required, other methods have been devised to ensure that a utility has the necessary funds to decommission the plant. Included among those other methods is the sinking fund approach where the utility establishes a separate fund for decommissioning costs. The nominal value of the initial investment for establishment of the fund and the accrued interest over the life of the reactor are set at levels that will ensure the availability of the necessary funding at the time of decommissioning. Under the sinking fund approach, then, annual charges for depreciation are based on the actual book cost of the nuclear unit and do not include (estimated) decommissioning costs.

From equation (1), the amount expended on taxes (T) is also considered an allowable expense for ratemaking purposes if the tax is the direct result of providing electricity. All IOUs are subject to a variety of taxes at various governmental levels. The type of tax and the amount may vary depending on the utility's location. Included among the taxes levied are Federal and state income or profits taxes, property taxes, gross revenue taxes, and franchise taxes levied in return for the right to operate. Although the inclusion of taxes as a determinant of revenue requirements poses no conceptual problems as an "above-the-line" expense for ratemaking purposes, the Federal tax effects of a number of types of expenditures are more complex and require detailed discussion. Those issues are discussed below.

Perhaps the most difficult and controversial aspect of the ratemaking procedure is determining a return on the utility's fixed investment [shown as RB*ROR in equation (1)]. There is no conceptual difference between these capital charges and other operating costs [OE, D, and T in equation (1)]. Each represents a portion of the cost of providing electricity. A utility must earn an equitable return on its invested capital, not only to compensate the contributors for their investment, but to maintain a sound credit rating and, hence, attract new capital. The classes of capital employed by IOUs include long-term debt, floating (short-term) debt, preferred stock, and common stock or equity.

Determining an equitable return to a utility's capital contributors involves three activities. First, the plant and equipment used in providing electricity must be determined. Second, a value must be placed on those assets. Finally, a fair rate of return must be established.

The rate of return must compensate the utility for all types of capital employed in its operation. Typically, a weighted average of the cost of all types of capital is used. While determining the cost of debt--both short- and long-term--and preferred stock is relatively straight forward, the cost of equity capital is more complicated.

3.3.2. Construction Work in Progress

In determining the rate base, a question of critical importance is the treatment of expenditures for construction programs that are not yet complete. The economic issue is the time period when an electric utility is allowed to recover the capital cost of on-going, unfinished construction programs from ratepayers.

In general, a new construction program is characterized by labor, material, and overhead expenditures. Examples of the latter are legal fees, insurance, and taxes. Under generally accepted financial accounting standards, these construction costs are capitalized during the construction period in a Construction Work in Progress (CWIP) account. The cumulative amount of CWIP is treated as an asset on the balance sheet. When the construction program is completed, the accumulated CWIP is transferred to an appropriate property account and depreciated over its estimated useful life.

An additional cost incurred in an on-going construction activity is the capital charge associated with financing the construction program. If the issuance of debt is the financing method chosen, the cost of capital is simply the interest expense on the securities issued. If the construction program is financed out of stockholders' equity (retained earnings, for example) the cost of capital is the opportunity cost of using the funds in an alternate investment.

While the treatment of "out-of-pocket" expenditures on labor, material, and overhead construction costs for new construction programs is universally accepted by regulatory bodies, the treatment of capital compensation is much more controversial and, consequently, has resulted in different approaches. Three approaches are commonly used to compensate utilities for capital employed in a construction program. Each has a different effect on the cash flow of the utility and, hence, its financial soundness. First, CWIP can be allowed in the rate base. Second, CWIP can be disallowed from the rate base but a return to (or, alternatively, cost of) capital employed in the construction program is imputed. Third, CWIP can be allowed in the rate base with a corresponding offset to required revenues of the utility by the amount of AFUDC that is imputed. Each of the approaches will be discussed in turn.

Under the first approach, the entire amount of accumulated CWIP is allowed in the rate base.[1] As a result, the utility is allowed to earn a current return on funds expended for new construction activity. Theoretically, the inclusion of CWIP in the rate base allows the utility the opportunity to generate a cash flow currently and, consequently, the cost of capital is recovered currently. Current ratepayers, then, bear the financing burden of a not-yet-complete construction program.

Under the second method, disallowing CWIP in the rate base, a return for capital employed in the construction program--called Allowance For Funds Used During Construction (AFUDC)--is imputed. For the debt portion of funds used (assuming that the construction program is financed partially from debt capital and partially from equity capital), the actual interest rate on the securities is used. For the equity portion, the opportunity cost is imputed using a methodology similar to the one used in determining the equity return portion of the return on rate base. In the current period, the total financing cost

[1]In general, only relatively high-cost, multi-period construction programs are of interest here. The difference between compensating a utility for the cost of capital used for construction of a 1,000 megawatt coal plant as opposed to residential consumers' distribution lines is obvious.

(AFUDC) is charged to CWIP and credited to income. From a financial standpoint, the imputation of AFUDC does not generate a current cash flow for the utility. Cash is generated from the construction program when the project is completed and the asset (formerly CWIP) is depreciated.

The third approach, which combines features of the first two, is called the AFUDC offset method. Concisely, CWIP is allowed in the rate base in computing the utility's revenue requirements; but it is offset by the amount of AFUDC imputed. The amount of current return for financing a construction program that the utility generates under this approach depends on (a) the return allowed the utility on its rate base as opposed to the rate used for the imputation of AFUDC and (b) the use of a compounding or a simple method to calculate AFUDC. For example, if the two rates are equal and AFUDC is compounded, the net effect is to exclude CWIP totally from the rate base.

A number of issues arise in the regulatory treatment of construction expenditures. A central issue is the question of equity. By allowing CWIP in the rate base, a regulatory body permits an individual utility to generate a current cash return on the construction program, but effectively makes current ratepayers bear the burden of financing costs associated with fixed investment that will contribute to providing electricity in the future. On the other hand, by disallowing CWIP in the rate base, the financing costs of new construction activities are deferred to years when the assets are actually used; but the utility must then generate capital service charges out of the current period's operations. Disallowing CWIP in the rate base can pose significant problems for a utility attempting to utilize capital markets for funding sources. Although AFUDC represents current period income for financial accounting purposes, it does not generate a current cash flow and, therefore, is generally viewed as "soft earnings" by the investment community.

In actual practice, a regulatory body may impose a combination of two or all three approaches to CWIP treatment in a given rate case depending on prevailing legislation in the state, commission policy, and the financial health of the utility. For example, a portion of CWIP could be allowed in the current period's rate base for determination of required revenues. Then, AFUDC is computed on the fraction not allowed in the rate base. The portion that is allowed could generate a positive cash flow for the utility. However, for the portion that is allowed in the rate base, an AFUDC offset may be imposed which, as discussed above, may or may not generate a current period cash flow.

Table 3.1 provides a summary of state-level treatment of CWIP by individual regulatory bodies in 1984. The table shows whether CWIP is allowed in the rate base and, if so, whether an AFUDC offset is required.

Table 3.1 shows that there are a wide variety of approaches to CWIP treatment for ratemaking purposes across individual states. Eleven states reported that no CWIP is allowed in the rate base. Under this circumstance, the AFUDC offset approach is not applicable. Five states reported that the total amount of CWIP is allowed in the rate base but with various conditions on the use of an AFUDC offset.

Table 3.1
Treatment of Construction Work in Progress
Investor-Owned Electric Utilities
By State and Federal Region
1984

Federal Region	State	Inclusion in Rate Base	AFUDC Offset
1	Connecticut	Conditional	No
	Maine	Total	Yes
	Massachusetts	None	No
	New Hampshire	None	No
	Rhode Island	None	No
	Vermont	Partial	No
2	New Jersey	Not uniform	Partial
	New York	Not uniform	Yes
3	Delaware	Partial	Partial
	Dist of Columbia	Conditional	No
	Maryland	Not uniform	Not uniform
	Pennsylvania	Conditional	No
	Virginia	Total	Conditional
	West Virginia	Partial	No
4	Alabama	Total	Yes
	Florida	Conditional	No
	Georgia	Not uniform	Yes
	Kentucky	Not uniform	Not Uniform
	Mississippi	Not reported	Not reported
	North Carolina	Partial	No
	South Carolina	Partial	Yes
	Tennessee	Not Reported	Not reported
5	Illinois	Not uniform	Yes
	Indiana	Not uniform	No
	Michigan	Total	Partial
	Minnesota	Total	Not uniform
	Ohio	Partial	No
	Wisconsin	Conditional	Yes
6	Arkansas	Conditional	No
	Louisiana	Not uniform	Yes
	New Mexico	Not uniform	Yes
	Oklahoma	Partial	Not uniform
	Texas	Partial	No

Table 3.1 (Continued)

Federal Region	State	Inclusion in Rate Base	AFUDC Offset
7	Iowa	None	No
	Kansas	Partial	No
	Missouri	None	No
8	Colorado	Not uniform	Yes
	Montana	Partial	No
	North Dakota	Not uniform	No
	South Dakota	None	No
	Utah	Partial	No
	Wyoming	Not uniform	Yes
9	Arizona	Not uniform	No
	California	Conditional	No
	Hawaii	None	No
	Nevada	Not uniform	No
10	Alaska	None	No
	Idaho	None	No
	Oregon	None	No
	Washington	None	No

SOURCE: National Association of Regulatory Utility Commissioners, 1984 Annual Report on Utility and Carrier Regulation.

Eleven states reported that a portion of CWIP is allowed in the rate base with differences in the application of an AFUDC offset to the amount allowed. Fourteen states reported that the treatment of CWIP is not uniform across individual utilities within the state. Presumably, those state regulatory bodies--and the 11 states that reported partial inclusion of CWIP in the rate base--determine CWIP ratemaking treatment on the basis of the financial health and construction program of individual utilities under their jurisdiction. Similarly, seven states reported that the treatment of CWIP is conditional on either the financial health of the utility or specific construction programs. The state of Connecticut, for example, reported that CWIP is allowed in the rate base if its exclusion leads to negative cash flow. The District of Columbia and the state of California allow CWIP accumulated on pollution control programs. Pennsylvania allows CWIP for coal conversion programs.

3.3.3. Treatment of Federal Taxes

As noted above, although the inclusion of various types of taxes in the determination of revenue requirements poses no conceptual problems as an allowed operating expense, the Federal tax effects of a number of expenditure categories are complex. Federal tax effects are complicated by depreciation accounting, the investment tax credit, and other "timing differences" and "permanent differences" between financial accounting and tax accounting.

"Timing differences" between financial (book) accounting and tax accounting arise when expenses are recorded for tax purposes in one year and for book purposes in another year or, alternatively, revenues are reported for tax purposes in one year and for book purposes in another. Over a sufficient number of years, the applicable items of revenue and/or expense have the same nominal effect on both financial and tax accounting. However, in the short term, differences arise.

One of the primary timing differences for all corporations--investor-owned utilities included--is depreciation of physical assets. With enactment of the amended Internal Revenue Code in 1954, taxable corporations were allowed to use accelerated depreciation rates (e.g., sum-of-the-years digits method; declining balance method; double declining balance method) in computing the depreciation charge in determining their Federal tax liability. Accelerated depreciation methods weight the early years of an asset's life with a larger depreciation charge than the straight-line method (equal charges over the asset's useful life). The rationale for this approach is that an asset makes a larger contribution to revenues during the early portion of its life than in later years.

Since generally accepted accounting principles require straight-line depreciation methods for financial or book purposes, a difference arises between book depreciation expense and tax depreciation expense. During the early years of an asset's life, tax depreciation is greater than book depreciation and, consequently, the current Federal income tax liability is less than the total Federal income tax expense in the financial records. On the other hand, during the later years of an asset's life, book depreciation expense is larger than tax depreciation expense for that asset and the actual Federal tax liability is greater than that reflected on the books for that asset. In the aggregate, however, for utilities undertaking relatively more costly construction programs for the expansion and replacement of fixed capital, tax depreciation expense is effectively larger than book depreciation expense.

Besides depreciation accounting, a number of other items of revenue and expense lead to timing differences between book accounting and tax accounting. Included among those are portions of an asset's cost (e.g., pension costs, payroll costs) that are capitalized during construction, depreciated over the asset's useful life when it comes "on-line", but are allowed as current period deductions for Federal income tax purposes.

Two primary methods of treating the Federal tax benefits associated with timing differences have historically been used by regulatory bodies. The first method, termed tax normalization, allows the utility to defer the tax benefits and amortize the amount over the useful life of the asset. A charge is made to current operations (provision for deferred taxes)--and allowed as an operating expense for ratemaking purposes--and a corresponding credit is made to a deferred liability (reserve for deferred taxes). When the timing difference "turns around", the reverse entry is made (i.e., income is credited and the reserve charged). Under the second method, termed flow-through accounting, no deferred reserve is established. The current tax benefits are not amortized, but impact the financial accounts and, therefore, ratemaking in the current period.

A similar regulatory option has historically existed for the investment tax credit (ITC). The ITC, first enacted in 1962, has a storied history. It was suspended in 1966, reinstated in 1967, terminated in 1969, reinstated in 1971, amended in 1975, and terminated again in 1986. Although it has been applied differently over the years since its initial enactment, its primary purpose has not changed: it was to act as an incentive for corporate taxpayers to replace, modernize, and expand production facilities. It specifies that taxpayers are allowed a dollar-for-dollar credit against their current Federal income tax liabilty for a specified percentage of the dollar amount of new investment in qualified plant. For electric utilities, the applicable percentage was originally limited to 3 percent but increased to 4 percent in 1971. With the amendments enacted in 1975, the credit was increased to 10 percent of investment in qualified property. The Tax Reform Act of 1986, however, eliminated the ITC on construction started after January 1, 1986.

From an accounting standpoint, the ITC represents a permanent savings in taxes rather than a deferral. The pertinent question concerns the year in which tax expense should be reduced for ratemaking purposes.

Similar to the treatment of deferred taxes, two methods historically have been used by regulatory authorities to account for the impact of the ITC. The first method requires a deferral of the credit in the year that it is realized. The amount of the credit is then amortized over the useful life of the property. The rationale behind this approach is that the ITC represents a reduction in the cost of property and, therefore, should have an impact on income as the asset in question is depreciated. The second method allows the entire amount of the credit to affect income in the year in which the asset is placed in service. The rationale is that the credit reduces the effective income tax rate in the current year and, consequently, should be reflected as such in current tax expense.

The impact of the two methods on ratemaking is similar to the deferred Federal tax expense discussed above. By utilizing the second method (taking the entire credit in the year in which it is realized), allowable tax expense is reduced for rate-making purposes and, consequently, required revenues and rates are lower than under the alternative method of establishing a deferred reserve for the credit and amortizing it over the useful life of the asset.

Both to illustrate some of the concepts discussed above and to summarize the types of income and non-income taxes provided for by investor-owned electric utilities, Table 3.2 provides the amount of taxes by type and the percentage of electric operating revenues accounted for by those taxes in 1984 by Federal region. Table 3.2 shows that investor-owned utilities provide for federal income taxes, sub-Federal (state and local) income taxes, and non-income (or other) taxes. An example of the latter is a property tax.

In total, investor-owned utilities provided for $19.8 billion of taxes in 1984, which accounted for 15.41 percent of their electric operating revenues. On a percentage of revenues basis, the largest of the five tax types presented in Table 3.2 is non-income taxes, accounting for 6.62 percent of revenues and nearly 43 percent of the total $19.8 billion tax provision. The smallest of the five tax types on a percentage of revenues basis was sub-Federal income taxes.

Table 3.2
Investor-Owned Electric Utilities
Analysis of Tax Provision
Amount and Percentage of Revenues
By Federal Region
1984

(Dollar Amounts in Millions)

Federal Region	Total Electric Operating Revenues	Total Tax Provision		Provision for Federal Income Taxes: Current Income Tax		Provision for Federal Income Taxes: Deferred Income Tax		Provision for Federal Income Taxes: Investment Tax Credit		Other Income Taxes		Non-Income Taxes	
		Amount	%	Amount	%	Amount	%	Amount	%	Amount	%	Amount	%
1	9,318.7	1,045.4	11.22	204.8	2.20	220.9	2.37	135.3	1.45	46.4	0.50	438.0	4.70
2	15,280.9	3,273.7	21.42	307.2	2.01	546.3	3.58	355.4	2.33	1.0	0.01	2,063.7	13.51
3	15,172.2	2,451.6	16.16	646.3	4.26	508.5	3.35	141.9	0.93	95.1	0.63	1,059.8	6.98
4	19,683.5	2,971.0	15.09	659.6	3.35	648.8	3.30	403.9	2.05	164.4	0.84	1,094.3	5.56
5	26,399.0	4,306.4	16.31	948.4	3.59	869.5	3.29	367.5	1.39	145.6	0.55	1,975.4	7.48
6	18,050.3	1,957.9	10.85	477.0	2.64	388.3	2.15	315.9	1.75	39.1	0.22	737.6	4.09
7	4,745.9	860.4	18.13	152.6	3.21	354.9	7.48	(12.5)	(0.26)	32.9	0.69	332.5	7.01
8	2,575.9	407.8	15.83	151.2	5.87	85.8	3.33	24.3	0.94	18.1	0.70	128.3	4.98
9	13,967.4	1,995.0	14.28	154.4	1.11	961.6	6.88	280.0	2.00	129.5	0.93	469.5	3.36
10	3,122.9	506.8	16.23	79.6	2.55	101.6	3.25	118.6	3.80	16.6	0.53	190.3	6.09
Total	128,316.9	19,775.7	15.41	3,781.1	2.95	4,686.2	3.65	2,130.4	1.66	688.7	0.54	8,489.3	6.62

SOURCE: Compiled from Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1984.

The total provision for Federal income taxes in Table 3.2--the sum of the provisions for current taxes, deferred taxes, and the investment tax credit--was \$10.6 billion or 8.26 percent of operating revenues in 1984. On a normalized tax basis, the entire \$10.6 billion provision for Federal income taxes would be allowed as an operating expense for ratemaking purposes. Using the flow-through or actual taxes paid approach, only the \$3.8 billion in current Federal income tax would be allowed as an operating expense for ratemaking purposes. Other income taxes and non-income taxes, of course, would be a legitimate operating expense under both approaches.[2]

On a regional basis, the investor-owned utilities comprising Federal region 2 in the states of New York and New Jersey experienced the largest tax burden on a percentage of revenues basis. More than 21 percent of their operating revenues were accounted for by taxes with non-income taxes accounting for the largest share of that total. On the other hand, the utilities in region 6 of the Southwest experienced the smallest tax burden on a percentage of revenues basis in 1984. Less than 11 percent of the revenues of the utilities in that region were accounted for by taxes in 1984.

3.4. STATE/MUNICIPAL ELECTRIC SYSTEMS

As noted in Chapter 2, there were more than 2,200 local, publicly owned electric utility systems in existence during 1984. The publicly owned systems include municipally owned utilities, public utility

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[2]A caveat is in order here. The total of other income taxes would be a legitimate operating expense for ratemaking purposes under the assumption that no sub-Federal political jurisdiction used deferred tax accounting in corporate income tax determination.

districts, joint action agencies, state systems, and county systems. The existence of over 2,200 state and municipal systems, operating in diverse geographical areas and under different types of regulatory and governing control, is a significant obstacle for making generalizations about the pricing and operation of those systems. However, by examining published material--including individual annual reports of the larger utilities--it is possible to draw some general conclusions about those systems.

The remainder of the discussion in this section addresses the control, regulation, and pricing of state/municipal systems and also addresses financial issues associated with their operation. The financial issues include depreciation, taxation, and the treatment of Construction Work in Progress (CWIP).

3.4.1. Control, Regulation, and Pricing

Table 3.3 provides a summary of the nature and extent of state-level economic regulation of publicly owned electric systems by state and federal region along with the number of publicly owned electric systems in each of the individual states divided between utilities and joint action agencies. A list of joint action agencies in existence in 1984 is provided in Appendix A. Table 3.3 also provides the total amount of end-use sales of state/municipal systems in 1984 by individual state and federal region. The corresponding percentage of total U.S. end-use sales is provided also. The nature and extent of economic regulation of state/municipal systems was derived from the National Association of Regulatory Utility Commissioners' 1984 Annual Report on Utility and Carrier Regulation [see National Association of Regulatory

Table 3.3
State/Municipal Electric Systems
Nature and Extent of State-Level Economic Regulation
Including Number of Utilities and Total End-Use Sales
By State and Federal Region
1984

		Number Of		1984 Sales (In Gwh)		Nature and Extent of Economic Regulation				
						Sales To Ultimate Consumers	Wholesale Sales			
Region	State	Utilities	JAAs	Amount	%		Auth	Govt	POUs	IOUs
1	Connecticut	6	1	1,336	0.40	Not regulated				
	Maine	7	1	173	0.05	Unqualified regulation				
	Massachusetts	40	1	4,614	1.39	If earnings exceed 8% of original plant cost	X			
	New Hampshire	5	0	98	0.03	Regulated outside municipal boundary	X	X	X	X
	Rhode Island	1	0	22	0.01	Unqualified regulation	X	X	X	X
	Vermont	15	1	644	0.19	Unqualified regulation				
	Total	74	4	6,887	2.08					
2	New Jersey	10	0	658	0.20	Authority limited by legislation or courts				
	New York	50	0	16,095	4.86	Not over utilities served by NYPA	X	X	X	X
	Total	60	0	16,753	5.06					
3	Delaware	9	1	905	0.27	Not regulated				
	Maryland	6	0	439	0.13	Unqualified regulation				
	Pennsylvania	35	0	1,298	0.39	Regulated outside municipal boundary	X			
	Virginia	18	0	2,460	0.74	Not regulated				
	West Virginia	2	0	53	0.02	Limited review authority over rate changes	X	X	X	X
	Total	70	1	5,155	1.56					
4	Alabama	36	1	10,586	3.20	Not regulated				
	Florida	33	1	17,275	5.22	Rate structure regulation				
	Georgia	52	1	4,592	1.39	Not regulated				
	Kentucky	30	0	4,151	1.25	Not regulated				
	Mississippi	25	1	2,812	0.85	Regulated outside of 1-mile boundary				
	North Carolina	72	2	11,951	3.61	Not regulated				
	South Carolina	22	1	8,811	2.66	Not regulated				
	Tennessee	63	0	43,552	13.16	Not Regulated				
	Total	333	7	103,730	31.35					

Table 3.3 (Continued)

Region	State	Number Of: Utilities	Number Of: JAAs	1984 Sales (In Gwh): Amount	1984 Sales (In Gwh): %	Nature and Extent of Economic Regulation: Sales To Ultimate Consumers	Wholesale Sales: Auth	Wholesale Sales: Govt	Wholesale Sales: POUs	Wholesale Sales: IOUs
5	Illinois	41	1	3,745	1.13	Not regulated				
	Indiana	72	1	4,849	1.47	Unqualified regulation			X	
	Michigan	41	2	4,512	1.36	Not regulated				
	Minnesota	125	4	4,593	1.39	Not regulated				
	Ohio	83	1	5,071	1.53	Not regulated				
	Wisconsin	83	3	4,399	1.33	Unqualified regulation	X	X	X	X
	Total	445	12	27,169	8.21					
6	Arkansas	15	0	2,586	0.78	Regulated outside municipal boundary				
	Louisiana	23	1	3,095	0.94	Not regulated				
	New Mexico	7	0	752	0.23	Regulated outside of 5-mile boundary				
	Oklahoma	65	1	3,405	1.03	Not regulated				
	Texas	76	3	24,313	7.35	Jurisdiction over Lower Colorado River Auth.				
	Total	186	5	34,151	10.32					
7	Iowa	140	4	3,249	0.98	Not regulated				
	Kansas	125	1	4,666	1.41	Regulated outside of 3-mile boundary	X	X	X	X
	Missouri	82	1	5,960	1.80	Not regulated				
	Nebraska	397	2	15,323	4.63	Not regulated				
	Total	744	8	29,198	8.82					
8	Colorado	30	2	3,930	1.19	Not regulated	X	X	X	X
	Montana	1	0	0	0.00	Unqualified regulation	X	X	X	X
	North Dakota	11	1	204	0.06	Not regulated				
	South Dakota	35	3	652	0.20	Not regulated				
	Utah	36	3	1,828	0.55	Not regulated				
	Wyoming	12	1	253	0.08	Regulated outside municipal boundary	X	X	X	X
	Total	125	10	6,867	2.08					

Table 3.3 (Continued)

		Number Of		1984 Sales (In Gwh)		Nature and Extent of Economic Regulation				
						Sales To Ultimate Consumers	Wholesale Sales			
Region	State	Utilities	JAAs	Amount	%		Auth	Govt	POUs	IOUs
9	Arizona	23	1	12,075	3.65	Not regulated				
	California	42	6	40,666	12.29	Not regulated				
	Hawaii	0	0	0	0.00	Not regulated				
	Nevada	9	0	1,032	0.31	Not regulated				
	Total	74	7	53,773	16.25					
10	Alaska	22	0	1,146	0.35	Full regulation when competition exists	X	X	X	X
	Idaho	12	0	2,002	0.61	Not regulated				
	Oregon	17	0	7,020	2.12	Not regulated				
	Washington	43	3	37,051	11.20	Not regulated				
	Total	94	3	47,219	14.27					
	US Total	2205	57	330,902	100.00					

SOURCE: National Association of Regulatory Utility Commissioners, 1984 Annual Report on Utility and Carrier Regulation, American Public Power Association, 1986 Public Power Directory, and data provided by the Edison Electric Institute.

JAAs - Joint Action Agencies
Auth - Public Authorities
Govt - U.S. Government
POUs - Publicly Owned Electric Utilities
IOUs - Investor-Owned Electric Utilities

X - Denotes that state has regulatory jurisdiction.

Utility Commissioners (1985)]. The number of utilities in each state was compiled from the American Public Power Association's <u>1986 Public Power Directory</u>. The information on state-level jurisdiction over publicly owned utilities is divided between sales to ultimate consumers (or retail sales) and wholesale (or sales for resale) sales. The four categories under wholesale sales include sales to public authorities, the U.S. government, investor-owned utilities, and publicly owned utilities. With the exception of Colorado, an affirmative response in any of those categories signifies that the state-level regulatory authority has economic jurisdiction over those sales in the same manner as that listed for ultimate sales. In Colorado, wholesale sales are regulated if those sales occur outside the municipal's boundary.

Table 3.3 shows that the four states that comprise Region 7 had the largest number of individual systems in 1984 (744 systems), while Region 2 had the smallest number (60 systems). The state of Nebraska with 399 systems has the largest number of any of the states. Included in the total for Nebraska are 213 locally owned systems that are operated by the Nebraska Public Power District, 22 locally owned systems that are operated by the Loup River Public Power District, and six other locally owned systems that are leased to other utilities. The midwestern states of Kansas, Minnesota, and Iowa also account for a large number of locally owned systems totalling over 125 systems in each. Hawaii is the lone state without a publicly owned system and the states of Rhode Island and Montana have one each.

In contrast to IOUs, very few state-level regulatory bodies have jurisdiction over the rate level and rate structure of state/municipal electric systems. Only seven states reported that they had unconditional jurisdiction over retail sales of publicly owned systems. Those seven states are Rhode Island, Vermont, and Maine in Region 1, Maryland in Region 3, Indiana and Wisconsin in Region 5, and Montana in Region 8. In addition, the state of New York has jurisdiction over the retail sales of publicly owned systems that are not provided power from the New York Power Authority, a state corporation.

Seven states reported that they had ratemaking jurisdiction for municipal system retail sales that occur outside of various radii of the incorporated limits of the municipality. Four states (New Hampshire, Pennsylvania, Arkansas, and Wyoming) have jurisdiction over sales to customers outside of the incorporated limits of the municipality. Three states (Mississippi, New Mexico, and Kansas) have jurisdiction over sales made over wider boundaries than the incorporated limits of the city.

Table 3.3 shows that 29 states reported that the retail sales of state/municipal systems are not regulated by state-level regulatory authorities. In general, utilities in states in the Midwest and West (Regions 7, 8, 9, and 10) are the least subject to state-level regulation.

The general conclusion drawn from Table 3.3 is that a nominal amount of publicly owned utility electricity sales in the United States is subject to regulation by state-level regulatory bodies. The seven states that reported unconditional regulatory control over the rates of state/municipal electric systems accounted for only a little more than three percent of the end-use sales of that ownership type.

The most comprehensive source of information on the control, regulation, and rate-setting authority of publicly owned electric utilities is the American Public Power Association's three studies entitled Survey of Administrative and Policy Making Organization of Municipally Owned Electric Utilities in the United States conducted in 1967, 1977, and 1982. Besides control and regulation of publicly owned systems, the surveys encompassed such areas as "tax" payments and compensation for members of the controlling body.

Table 3.4 summarizes the results of the three surveys on the question of local control of municipally owned utilities. Based on responses from the 475 utilities in the 1982 survey, 53 percent of the utilities were under the direct control of the governing legislative body, while the remaining 47 percent were under the jurisdiction of an independent utility or power board. For those municipals under the jurisdiction of an independent board, 24 percent were controlled by elected boards and the remainder were controlled by boards that are appointed by either the mayor, the city's governing board, or by the mayor with approval of the city governing board. Although not included in Table 3.4, 43 percent of large municipals (more than 15,000 meters), are under the jurisdiction of the governing body and 57 percent are under the control of an independent utility board.

The survey results for 1977 and 1967 are similar with repect to the percentage of independent controlling boards that are elected, but are dissimilar for the percentage of utilites that were controlled by the elected governing body and an independent board. These respective percentages were 63 and 37 percent in 1967 and 49 and 51 percent in 1977.

Table 3.4
Control of Municipally Owned Electric Systems
Survey Results
1967, 1977, and 1982

Year	Total Reporting	Control: Governing Body	Independent Board: Total	Independent Board: Elected	Independent Board: Appointed
1982	475	254 (53%)	221 (47%)	52 (24%)	169 (76%)
1977	376	186 (49%)	190 (51%)	39 (20%)	151 (80%)
1967	599	377 (63%)	222 (37%)	47 (21%)	175 (79%)

SOURCE: American Public Power Association, Survey of Administrative and Policy-Making Organization of Municipally Owned Electric Utilities in the United States, September 1982, August 1977, and August 1967.

A plausible explanation for the decrease in number of utilities under the jurisdiction of the elected governing body is the increase in complexity of municipal electric operations (increase in generating capacity of municipals and formation of joint action agencies, as examples) which requires a corresponding increase in expertise in controlling the operations of the electric system.

Table 3.5 presents the survey results for 1967, 1977, and 1982 on the ultimate ratemaking authority for the responding utilities, segregated between municipals under the control of the governing body and those under the control of an independent utility board. The survey re-

Table 3.5
Ratemaking Authority
Municipally Owned Electric Systems
Survey Results
1967, 1977, and 1982

Survey Year	Ratemaking Authority	Under Control Of- Governing Body	Independent Board
1982	Governing	95%	11%
	Independent	0%	81%
	Other	5%	8%
	Total	100%	100%
1977	Governing	96%	17%
	Independent	0%	78%
	Other	4%	5%
	Total	100%	100%
1967	Governing	89%	
	Independent		82%

SOURCE: American Public Power Association, Survey of Administrative and Policy-Making Organization of Municipally Owned Electric Utilities in the United States, September 1982, August 1977, and August 1967.

sults for 1967 were not presented in detail consistent with the results of 1977 and 1982.

Table 3.5 shows that for 95 percent of the utilities under the control of the city governing body in 1982, the ultimate rate-setting authority rests with the governing body itself. Rates for the other five percent are under the jurisdiction of other authorities which include state-level regulatory bodies. On the other hand, 81 percent of the municipals under the jurisdiction of an independent utility board have their retail electric rates set by that independent board. The remainder are set by the governing body of the municipality (11 percent) or other bodies--state-level authorities and town meetings, as examples. The survey results for 1977 are similar for POUs under the control of the local governing body. For independent board-controlled municipals, however, there was a decline in the percentage of utilities whose ratemaking authority was vested in the governing body from 1977 (17 percent) to 1982 (11 percent).

The information provided by NARUC's annual report and the data contained in APPA's three surveys of municipals strongly suggest that a very large portion of the electric sales of state and municipal systems --taken as a whole--are not subject to the traditional economic regulation of state-level authorities (recovery of operating costs plus a fair return on rate base). This result and the varied character of the political and economic climates in which municipals operate make generalizations about their pricing incentives difficult. In contrast to ratemaking for investor-owned utilities, state and municipal systems do not, in general, price electricity to recoup a fair or equitable return on rate base plus other operating expenses.

However, they do share one common constraint: the requirement to generate a net margin (net income) sufficient to attract external funding at a reasonable rate. In terms of pricing incentives, the pricing strategy is to set rate levels in order to generate revenues sufficient to cover all operating costs (including the cost of debt) plus a net margin large enough to generate a sufficiently large interest coverage ratio. A rule-of-thumb ratio is 2.0. The ratemaking scheme of state/municipal systems begins at the "bottom line" (net income) which is used to determine the required revenues or rate level of the utility.

The rationale for this hypothesis lies in the determination of bond ratings and, hence, the cost of debt capital, determined by the security rating agencies (e.g., Moodys, Standard and Poor's). In general, two factors are involved. First, the ability of a utility to service or, alternatively, "turn over" its annual fixed interest charges is considered. An indicator widely used to measure that ability is the interest coverage ratio. Second, the rating agencies consider the economic base of the utility's service area or the incorporated boundaries of the municipality and its environs. Factors considered here are the level and type of economic activity (e.g., service-oriented versus heavy industry orientation) and the potential for future growth.

3.4.2. Depreciation

Since state and municipal systems are exempt from Federal taxation, the issue of accelerated cost recovery or tax depreciation rates is not applicable. For financial accounting or "book" purposes, capital equipment is generally depreciated on a straight-line basis. The estimated useful life of the assets in service for straight-line book depreciation purposes in general does not differ from the ranges utilized by investor-owned electric utilities.

3.4.3. Taxation

Although state and municipal systems are exempt from Federal taxation, they make payments to varying degrees in the states and localities in which they operate. The amount and type of payment is determined to a large extent by the controlling body of the utility. An indication of the amount and type of "tax" expenditures are provided in the three previously mentioned surveys of municipal utilities conducted by the American Public Power Association. The relevant information for the 1967, 1977, and 1982 survey years is summarized in Table 3.6.

Table 3.6 presents information on the percentage of responding utilities that make direct payments and indirect payments (electricity without charge, for example) to local governments; the percentage of utilities that use a formula for determining the payments; and the percentage of operating revenues that were paid to local governments either directly or indirectly. Unfortunately, a consistent set of information was not available across the three surveys for all categories of data.

Based on responses from the 475 state/municipal electric systems included in the 1982 survey, 92 percent of the respondents make direct payments to local municipalities. The direct payments can take the form of actual taxes, in lieu-of-tax payments, or simple transfers to the general fund of the local government. Additionally, 46 percent of the 475 utilities make some form of indirect payment (contributed services) to local governments. Only 2 percent of the utilities make no contribution to the government. For utilities making direct payments to the local government, the percentage increased from 82 percent of the 376 responding systems included in the 1977 survey.

Table 3.6
Payments to Local Government
Municipally Owned Electric Systems
Survey Results
1967, 1977, and 1982

	1982	1977	1967
Payments to Local Government (Percentage of Companies):			
Direct	92	82	NA
Indirect	46	NA	NA
None	2	NA	NA
Method for Direct Payments (Percentage of Companies):			
Arbitrary	36	37	40
Formula	64	63	60
Percentage of Operating Revenues Paid to Local Government (Direct and Indirect)	6.9	7.6	10.1

NA - Not Available

SOURCE: American Public Power Association, Survey of Administrative and Policy-Making Organization of Municipally Owned Electric Utilities in the United States, September 1982, August 1977, and August 1967.

Direct payments to local governments are made in one of two ways. The first is a formula. Under this method, the municipal is required to make payments on the basis of a pre-defined formula. The formulae include percentage of gross revenues, percentage of earnings, percentage of equity on surplus, or the equivalent amount that an investor-owned utility would be obligated to pay. Based on the 1982 survey results, 64 percent of the responding utilities use this procedure (see Table 3.6). The other method of direct payments is an arbitrary amount, presumably set on an annual basis. Table 3.6 shows that 36 percent of the utilities use this procedure. The percentage of utilities determining direct payments on the basis of formulae and arbitrary methods are consistent across the three surveys.

The last category in Table 3.6, Percentage of Operating Revenues Paid to Local Governments, shows the percentage of all payments made to local governments--both direct and indirect. According to the survey results, there has been a significant decline in the percentage of operating revenues distributed to local governments from 1967 (10.1 percent) to 1982 (6.9 percent). One of the contributing factors to this decline could be the growth of investment in generation and transmission facilities by municipally owned systems that requires an increasing use of internally generated funds for construction purposes.

To gain a better understanding of the "tax" payments and contributed services of state/municipal electric systems, a detailed analysis of the annual reports of the 162 electric systems that comprise the Energy Information Administrations's annual report on publicly owned electric utilities[3] was conducted. While the 162 electric systems contained in the EIA publication represent less than 10 percent of the total number of such systems in existence, they do represent 162 of the largest systems. In 1984, for example, the 162 systems accounted for

[3]Annually, summary information on the 162 systems is presented in Financial Statistics of Selected Electric Utilities. Although individual utility data are not presented in that publication, the annual reports of the 162 utilities are on file at the Federal Energy Regulatory Commission.

57.6 percent of the total operating revenues of state/municipal electric systems. On the basis of sales to ultimate consumers, the 162 systems accounted for 52.9 percent of the total.[4]

Table 3.7 presents a summary of the study of the tax payments and contributions made by the 162 electric systems in 1984, categorized by the ten Federal regions of the United States. The table provides total revenues for all of the utilities in a specified region, the nominal value of taxes and contributions by type and in total, and the percentage of operating revenues accounted for by these taxes and contributions. As noted at the bottom of the table, the data in Table 3.7 was compiled from Schedule XIV for each of the 162 utilities' annual submission of Form EIA-412.

Tax payments in Table 3.7 are direct expenditures by the utility under existing tax laws. Tax equivalents are expenditures made in-lieu-of-taxes. General funds show the contributions made by utilities to local political jurisdictions. Other-net includes services provided by utilities to the local political jurisdiction, net of contributions and services provided by the political jurisdiction to the utility. Services provided by the utilities include, for the most part, electricity provided gratis to various organs of the local government. Contributions and services provided by the local government include office space, water, or other professional services (engineering and legal services, as examples). Of the $43.2 million of net services provided by

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[4]The percentages of total state/municipal electric system revenues and ultimate sales accounted for by the 162 utilities were calculated as the ratio of revenues and sales provided by EIA's annual publication to total state/municipal system revenues and ultimate sales as provided in the American Public Power Association's <u>1986 Public Power Directory</u>.

Table 3.7
State/Municipal Electric Systems
Taxes, Tax Equivalents, Contributions, and Services
Dollar Amounts and Percentage of Revenues
By Federal Region
1984

(Dollar Amounts in Thousands)

Region	Number of Utilities	Total Electric Operating Revenues	Payments by Type in Nominal Dollars and as a Percentage of Total Revenues									
			Tax Payments		Tax Equivalents		General Funds		Other - Net		Total	
			Amount	%	Amount	%	Amount	%	Amount	%	Amount	%
1	14	359,659	2,166	0.60	2,684	0.75	5,156	1.43	2,805	0.78	12,811	3.56
2	5	1,280,571	187	0.01	1,275	0.10	400	0.03	68	0.01	1,930	0.15
3	7	100,648	69	0.07	1,916	1.90	6,272	6.23	892	0.89	9,149	9.09
4	33	1,791,519	5,231	0.29	11,182	0.62	80,141	4.47	7,384	0.41	103,938	5.80
5	25	480,685	2,735	0.57	8,818	1.83	6,834	1.42	2,688	0.56	21,075	4.38
6	15	1,374,074	1,886	0.14	8,490	0.62	71,467	5.20	19,597	1.43	101,440	7.38
7	19	1,488,888	271	0.02	32,726	2.20	4,664	0.31	9,455	0.64	47,116	3.16
8	6	343,150	584	0.17	7,500	2.19	1,047	0.31	314	0.09	9,445	2.75
9	22	3,238,727	49,769	1.54	35,307	1.09	91,494	2.82	120	0.00	176,690	5.46
10	16	1,051,855	71,521	6.80	7,514	0.71	0	0.00	(150)	(0.01)	78,885	7.50
Total US	162	11,509,776	134,419	1.17	117,412	1.02	267,475	2.32	43,173	0.38	562,479	4.89

SOURCE: Compiled from Energy Information Administration, Form 412, Schedule XIV, "Taxes, Tax Equivalents, Contributions, and Services During Year," Individual Utilities, 1984.

electric systems to local political jurisdictions in 1984, $47.5 million was accounted for by services provided by the utilities. That amount was offset by $4.3 million contributed to the utilities from local governments.

On a regional basis, the most salient characteristic of the data provided in Table 3.7 is the relatively small percentage of total revenues accounted for by taxes and contributions in Region 2 (New York and New Jersey). For the five utilities of that region, only 0.15 percent of total revenues in 1984 was expended on taxes and contributions. The reason for the low percentage is the inclusion of the New York Power Authority in that region which, in 1984, generated revenues of $1,220.2 million--or 95.3 percent of the $1,280.6 million of revenues listed in Table 3.7 for Region 2--but made no tax or in-lieu-of-tax payements or general fund contributions and did not contribute services to local governmental bodies. Excluding the New York Power Authority, 3.19 percent of the total revenues of the four remaining systems in Region 2 were expended on taxes and contributions. Of that percentage, 0.31 percent was for taxes, 2.11 percent for tax equivalents, 0.66 percent for general fund contributions, and 0.11 percent in the form of net services provided to local governments.

The five states that comprise Region 3 had the largest total percentage of revenues in the form of taxes and contributions.[5] Of the seven utilities included in the sample, the cities of Danville and Martinsville in Virginia accounted for 40.1 percent of Region 3's total

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[5]Only the states of Maryland, Pennsylvania, and Virginia have utilities represented in the 162-company EIA sample. The states of Delaware and West Virginia are not represented.

revenues of $100.6 million in 1984 and expended 10.0 percent of their revenues on general fund contributions.

The 15 public electric systems in the states of Arkansas, New Mexico, Oklahoma, and Texas that comprise Region 6[6] experienced the largest net contributions of services to local political jurisdictions--1.43 percent of total operating revenues. In large measure, this is attributable to the city of San Antonio which had $544.1 million in revenues in 1984--39.6 percent of Region 6's total--and contributed $16.5 million in services to the city.

The 16 utilities representing the states of Alaska, Oregon, and Washington in Region 10[7] expended 6.8 percent of operating revenues on direct tax payments in 1984, the largest percentage of any of the Federal regions. While 13 of the 16 utilities included in the region's sample reported making some form of direct tax payment, the amount is accounted for in large measure by three public systems--the cities of Seattle and Tacoma and Public Utility District No. 1 of Snohomish County. Those three systems' combined revenues of $522.9 million represented a little less than one-half of the total revenues in Region 10 in 1984. Their reported tax payments of $48.6 million accounted for 9.3 percent of their operating revenues.

Table 3.7 shows that, in the aggregate, the 162 publicly owned electric systems expended 4.89 percent of their total electric operating

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[6]Region 6 is comprised of five states. The state of Louisiana is not represented in the 162-company EIA sample.

[7]Four states comprise Region 10. The state of Idaho is not represented in the EIA sample.

revenues on taxes and contributions--1.17 percent for direct tax payments, 1.02 percent for tax equivalents or in-lieu-of-tax payments, 2.32 percent on fund contributions, and 0.38 percent on net service contributions. The total percentage of 4.89 percent is significantly less than the 6.9 percent reported in the 1982 American Public Power Association survey (see Table 3.6). However, since the latest year for APPA's survey results was 1982--and the percentage has declined from 1967 to 1977 to 1982--the results are not necessarily inconsistent.

The 1982 APPA survey results (Table 3.6) for the percentage of companies that made direct and indirect contributions to local governments differs substantially from the results obtained using the 162-utility EIA sample. Table 3.6 shows that 92 percent of the 475 responding utilities reported making direct contributions to governments, while 46 percent reported making indirect contributions. For the 162-utility EIA sample, 136 utilities--or 84.0 percent of the total--made direct contributions to governments (that is, tax payments, tax equivalents, and general funds in Table 3.7), while only 40 utilities--or less than one quarter of the total--reported indirect contributions to governments in the form of unrequited street and highway lighting, municipal pumping, and the like.

The presentation of taxes and contributions made by state/municipal utilities in Table 3.7 masks the concentration payments by a relatively few electric systems. Of the $134.4 million in tax payments reported by the 162-utility EIA sample, for example, five systems--the Salt River Project in Arizona, the cities of Seattle, Tacoma, and Los Angeles, and Public Utility District No. 1 of Snohomish County in Washington--

accounted for $95.9 million or 71.4 percent of the total reported tax payments. Including the next five largest (the Public Utility Districts of Clark, Cowlitz, Chelan, and Grays Harbor counties in Washington and the city of Orlando), ten of the 162 utilities accounted for $116.8 million or 86.9 percent of the total tax payments reported.

Although not as pronounced, similar results hold for the payment of tax equivalents. The Salt River Project in Arizona, the Omaha Public Power District, and the cities of Orlando, Colorado Springs, and Kansas City accounted for $56.9 million in tax equivalents in 1984 or 48.5 percent of the $117.4 million total. With the addition of the next five largest expenditures on tax equivalents by the cities of San Antonio and Eugene, Oregon, the Nebraska Public Power District, and the cities of Springfield, Missouri and Lincoln, Nebraska, the total in-lieu-of-tax payments by the ten largest utilties increases to $78.3 million or 66.7 percent of the total.

For contributions to general funds, the cities of San Antonio, Los Angeles, Tallahassee, Orlando, and Gainsville accounted for 57.3 percent of the total of $267.5 million. Including the next five largest (the cities of Lakeland, Palo Alto, Albany, Ocala, and Anaheim), the amount increases to $180.9 million or 67.6 percent of the total.

Table 3.8 presents a summary of eliminating both the top 5 and top 10 utilities making tax payments, in-lieu-of-tax-payments, and general fund contributions for the United States in total. The first line of the table reproduces the U.S. total in Table 3.7. For each of the different expenditure types, data on total electric revenues, nominal payment amounts, and the percentage of revenues that the payment consti-

Table 3.8
State/Municipal Electric Systems
Taxes, Tax Equivalents, and Contributions
In Total and Excluding Largest 5 and 10 Expenditures
Dollar Amounts and Percentage of Revenues
1984

(Dollar Amounts in Thousands)

		Payments by Type in Nominal Dollars and as a Percentage of Total Revenues					
	Total Electric Operating	Tax Payments		Tax Equivalents		General Funds	
Category	Revenues	Amount	Pct.	Amount	Pct.	Amount	Pct.
Total US (Per Table 3.5)	11,509,776	134,419	1.17	117,412	1.02	267,475	2.32
Tax Payments:							
Top 5	2,381,143	95,917	4.03				
Remaining 157	9,128,633	38,502	0.42				
Top 10	2,843,675	116,824	4.11				
Remaining 152	8,666,101	17,595	0.20				
Tax Eqivalents:							
Top 5	1,394,835			56,900	4.08		
Remaining 157	10,114,941			60,512	0.60		
Top 10	2,766,049			78,281	2.83		
Remaining 152	8,743,727			39,131	0.45		
General Funds:							
Top 5	2,075,594					153,340	7.39
Remaining 157	9,434,182					114,135	1.21
Top 10	2,444,278					180,918	7.40
Remaining 152	9,065,498					86,557	0.95

SOURCE: Compiled from Energy Information Administration, Form 412, Schedule XIV, "Taxes, Tax Equivalents, Contributions, and Services During Year," Individual Utilities, 1984.

tutes are presented for the top 5 and 10 utilities making the expenditure and the remaining 157 and 152 utilities, respectively. In each of the two sub-categories under tax payments, tax equivalents, and general funds, total revenues and the total of the individual expenditure types equals the U.S. total displayed in the first row of the table.

Table 3.8 shows that by eliminating the top 5 contributors of tax payments from the 162-utility sample, the remaining 157 utilities expended an average of 0.42 percent on direct tax payments. Excluding the top 10 utilities, the remaining 152 expended only 0.20 percent of revenues on taxes.

For tax equivalents, the largest 5 utilities expended 4.08 percent of revenues. Excluding them, the remaining 157 expended 0.60 percent. By excluding utilities with the largest 10 expenditures, the remainder of the utilities paid only 0.45 percent of revenues on tax equivalents.

Similarly, the U.S. total of 2.32 percent of operating revenues accounted for by contributions to general funds is drastically altered by excluding the top 5 and top 10 utilities making general fund contributions. By excluding the top 5 that expended 7.39 percent of operating revenues on funds contributions, the remaining 157 utilities expended only 1.21 percent--a little more than one-half of the U.S. total. Excluding the top 10 contributors, the remaining 152 expended only 0.95 percent of their operating revenues on general funds contributions.

3.4.4. Construction Work in Progress

In contrast to investor-owned utilities, the treatment of CWIP by individual state and municipal systems is more difficult to determine because of the large number of such systems in existence. As discussed above, the treatment of CWIP by IOUs is determined by individual state regulatory bodies. An Allowance For Funds Used During Construction (AFUDC) is imputed for the amount of CWIP not allowed in the rate base. The amount of CWIP included or excluded varies from one jurisdiction to another and from one rate case to another in a given jurisdiction.

The only published source of financial information on state/municipal electric systems in detail sufficient to isolate the amount of CWIP and associated AFUDC is EIA's annual publication Financial Statistics of Selected Electric Utilities. For 1984, the publication presented financial information for 162 state/municipal electric systems out of more than 2,200 systems in existence.[8] Although the 162 systems represented only 52.9 and 57.6 percent of total state/municipal system electric activity in terms of end-use sales and revenues, respectively, it is presumed that a large majority of construction work in progress is accounted for by those 162 systems. The 162 utilities represented in the EIA sample are some of the largest publicly owned systems and tend to be involved in larger construction projects which have long lead construction times--the construction of generating facilities, for example--in contrast with the many smaller systems which are primarily distributors of electricity and not involved in construction programs where calculation of AFUDC would be a consideration.[9]

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[8]The publication only presents summary information aggregated across the 162 state/municipal systems. However, data for individual utilities that comprise the aggregate are available from EIA upon request.

[9] The 162 companies included in the annual EIA statistical summary of publicly owned electric systems are not the 162 largest in any measure of that term. According to a ranking of the 20 largest state/municipal electric systems for 1984 in terms of customers served, net electric plant, total sales, and electric revenues by the American Public Power Association in its 1986 Public Power Directory, the EIA sample of 162 publicly owned systems excludes six, four, six, and seven of the largest systems in terms of customers, net plant, sales, and revenues, respectively. Excluding the Puerto Rico Electric Power Authority, the most prominent of the utilities excluded are the Jacksonville, Florida Electric Authority; the Memphis, Tennessee Light, Gas, and Water Division; Nashville, Tennessee Electric Service; Knoxville, Tennessee Utilities Board; and Chattanooga, Tennessee Electric Power Board.

The information presented in Table 3.9 summarizes utility activity reported for CWIP and AFUDC by the 162 companies included in the 1984 report by the ten Federal regions. Regions 4, 6, and 9 dominate the reported amounts for AFUDC and average CWIP in 1984, accounting for 90.7 and 81.0 percent of reported AFUDC and average CWIP, respectively. Three systems (the Salt River Project in Arizona, San Antonio, Texas and the Municipal Electric Authority in Georgia), one in each of the aforementioned regions, accounted for 68.9 and 53.1 percent, respectively, of the 162-utility total AFUDC and average CWIP in 1984. Table 3.9 also shows that the five systems comprising Region 2 and the seven systems comprising Region 3[10] did not have an associated capitalized interest credit for the average CWIP balance in 1984.

Although not shown in Table 3.9, only 26 of the 162 state/municipal systems included in the report had a current-period credit for AFUDC in 1984. Thus, 136 state/municipal systems did not report a credit for AFUDC. Several systems with large CWIP balances did not impute an associated amount for AFUDC. Of the 30 systems with average CWIP balances in excess of $10 million, 17 did not report a credit for AFUDC. Of the 12 systems with average CWIP balances in excess of $100 million, five did not report an AFUDC credit.

If the information presented in Table 3.9 were for IOUs, the results would imply that, for the 26 companies reporting AFUDC, only a fraction of construction expenditures affected current-period rates. On the other hand, for systems reporting large CWIP balances but not a

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[10]See Table 3.5 for a listing of the number of electric systems that comprise each of the ten federal regions in the EIA sample.

Table 3.9
State/Municipal Electric Systems
Allowance for Funds Used During Construction (AFUDC)
and
Average Construction Work in Progress (CWIP)
By Federal Region
1984

(Dollar Amounts in Thousands)

	AFUDC		Average CWIP*	
Region	Amount	%	Amount	%
1	6,929	2.0	62,095	1.0
2	0	0.0	214,313	3.5
3	0	0.0	7,595	0.1
4	134,518	38.4	1,331,669	21.8
5	112	0.0	126,671	2.1
6	47,263	13.5	1,378,410	22.6
7	8,884	2.5	393,317	6.4
8	11,193	3.2	237,706	3.9
9	136,184	38.8	2,235,927	36.6
10	5,501	1.6	115,337	1.9
Total	350,584	100.0	6,103,040	100.0

SOURCE: Compiled from Energy Information Administration, Financial Statistics of Selected Electric Utilties, 1984, Supplementary data on individual publicly owned electric systems.

*Computed as simple average of beginning-of-year and end-of-year balances.

credit for AFUDC, the results would imply that CWIP is currently incorporated in the rate base and, hence, the return for construction expenditures is recouped in current-period rates. For state/municipal systems that place little or no emphasis on the concept of "rate base," however, the interpretation of the results presented in Table 3.9 is unclear.

To gain a better understanding of the treatment of construction expenditures for ratemaking, the formal annual reports of a sample of 33 state/municipal electric systems were examined to determine the treatment of the cost of funds used in construction.[11] The 33 systems are listed by Federal region in Appendix B, Table B.1, along with the amount of CWIP for each at the end of 1984. The total amount of CWIP for these 33 systems represented more than 94 percent of the total CWIP of the 162 utilities included in EIA's annual financial summary of publicly owned electric systems. Table B.2 lists the 33 systems in descending order by the amount of CWIP at the end of 1984.

Three conclusions on the treatment of CWIP for rate-making purposes emerged from analyzing the annual reports of the 33 utilities. First, state/municipal electric systems generally compute and capitalize AFUDC as part of the total cost of construction projects. Although both debt and equity components of the cost are considered, typically the interest rate on borrowed funds is used because state/municipal systems are highly leveraged (to be discussed in Chapter 4). As with investor-owned

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[11]The formal annual reports are not the same as EIA Form-412 which is the basis for the statistics in EIA's annual financial review of the electric utility industry. The formal reports provide much broader detail on the operations and financial practices of the utilities in comparison with Form-412 which is primarily a statistical presentation. The sample of 39 utilities was selected on the basis of size and geographical dispersion.

systems, interest generally is capitalized on projects with a minimum construction cost--$1 million, for example--and a minimum construction period--over one year as an example.

The first 13 systems listed in Table B.2 had the largest CWIP balances of the 162 companies represented in the EIA sample at the end of 1984, accounting for more than 92 percent of the total CWIP in the sample. With the exception of Orlando, these electric systems capitalize AFUDC as a portion of the cost of electric plant. Orlando allows the cost of capital for construction to impact current period rates and, hence, AFUDC is not a part of the cost of construction projects. Of the 20 remaining systems, 10 impute a value for AFUDC and capitalize it as part of the construction cost.[12] The remaining 10 systems provided no indication of CWIP treatment. However, as Table B.1 shows, the amount of CWIP for these systems was generally negligible in 1984.

Second, a large number of state/municipal electric systems have adopted the provisions of Financial Accounting Standards Board Rule Number 62 on calculating the amount of interest to be capitalized and credited to income. The rule recommends net interest expense as the amount to be capitalized for the debt-financed portion of a project. Net interest expense is the amount of nominal interest payments less the amount earned upon investing the proceeds of any debt offering used for construction programs.

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[12]The ten systems include PUD-Chelan County, Lincoln, Tacoma, Owensboro, Platte River Power Authority, Eugene, Gainesville, Kansas City, PUD-Snohomish County, and Los Angeles.

Third, there is an indication that the published information on the EIA sample of utilities is inaccurately reported for the AFUDC credit. Many utilities show the credit as the net value of interest expense rather than as a separate line-item in the income statement. Two of the more prominent examples of that are the New York Power Authority and the Grand River Dam Authority which, in the EIA sample, reported $211.5 million and $315.5 million of average CWIP, respectivey, but reported no AFUDC credit. The credits are shown as a part of net interest expense.

3.5. RURAL ELECTRIC COOPERATIVES

As of December 31, 1984, there were 992 rural electric cooperatives (RECs) that had loans outstanding that are either insured or guaranteed by the Rural Electrification Administration (REA). In addition, there were 111 borrowers who had repaid their loans. Since the advent of REA in the mid-1930's, two borrowers have had their loans foreclosed. Of the 992 active REA borrowers, 929 are distribution borrowers, while the remaining 63 are power supply (or generation and transmission) borrowers. The former were advanced loans primarily for the construction of electric distribution systems. In 1984, more than 98 percent of the sales of distribution borrowers were made to ultimate consumers. Power supply borrowers are engaged primarily in the generation and transmission of electricity. In 1984, a little less than one percent of their sales were made to ultimate consumers.

As with state/municipal electric systems, the large number of RECs in diverse economic and operating environments poses a significant obstacle for making generalizations about their control and pricing strategies. The following discussion delineates some of the major characteristics of RECs. The format follows that used for state/municipal systems, with emphasis placed on regulation and pricing, depreciation, taxation, and the treatment of CWIP.

3.5.1. Regulation and Pricing

The REA does not perform a regulatory function with respect to cooperatives in the strict definition of that term, but merely functions as an oversight body to ensure that REA-insured and REA-guaranteed loans are protected from default. REA's primary interest in the operation of RECs is to ensure that electricity prices established by individual RECs are at a level sufficient to generate revenues that cover operating costs plus debt service charges. The rule-of-thumb or policy that has evolved is that, for distribution borrowers, the times-interest-earned ratio should exceed 1.5 and, for power supply borrowers, the corresponding ratio should be at least 1.0. Chapter 4 contains a comparison of realized interest coverage ratios for both distribution and power supply borrowers over the 1979-1984 period.

Table 3.10 provides a summary of state-level jurisdiction over RECs in 1984 along with the number of active borrowers in each of the individual states and by federal region. The amount of end-use sales by cooperatives in individual states with the corresponding percentage of the total is also provided. As noted at the bottom of the table, the source for the information on the extent of state-level regulation is the National Association of Regulatory Utility Commissioners' 1984 Annual Report on Utility and Carrier Regulation, while the number of cooperatives in individual states with loans outstanding is contained in REA's annual report on cooperatives. The total of 991 active borrowers

Table 3.10
Rural Electric Cooperatives
Nature and Extent of State-Level Economic Regulation
Including Number of Cooperatives and Total End-Use Sales
By State and Federal Region
1984

					Nature and Extent of Economic Regulation				
		Number of	1984 Sales (In Gwh)		Sales To	Wholesale Sales			
Region	State	Cooperatives	Amount	%	Ultimate Consumers	Auth	Govt	POUs	IOUs
1	Connecticut	0	0	0.00	Not regulated				
	Maine	4	81	0.05	Unqualified regulation			X	X
	Massachusetts	0	0	0.00	Not regulated				
	New Hampshire	1	393	0.25	Unqualified regulation	X	X	X	X
	Rhode Island	0	0	0.00	Unqualified regulation	X	X	X	X
	Vermont	3	157	0.10	Unqualified regulation				
	Total	8	631	0.40					
2	New Jersey	1	82	0.05	Not regulated				
	New York	4	114	0.07	Not regulated				
	Total	5	196	0.12					
3	Delaware	1	327	0.21	Unqualified regulation				X
	Maryland	2	1,578	1.00	Unqualified regulation	X	X	X	X
	Pennsylvania	13	1,509	0.95	Not regulated				
	Virginia	14	3,681	2.32	Unqualified regulation				
	West Virginia	1	32	0.02	Unqualified regulation	X	X	X	X
	Total	31	7,127	4.50					
4	Alabama	24	4,224	2.67	Not regulated				
	Florida	16	5,568	3.52	Rate structure regulation				
	Georgia	44	12,064	7.62	Not regulated				
	Kentucky	28	13,633	8.61	Unqualified regulation	X	X	X	X
	Mississippi	24	8,001	5.05	Not regulated				
	North Carolina	29	6,042	3.81	Not regulated				
	South Carolina	22	4,787	3.02	Not regulated				
	Tennessee	24	10,210	6.45	Not regulated				
	Total	211	64,529	40.74					

Table 3.10 (Continued)

Region	State	Number of Cooperatives	1984 Sales (In Gwh) Amount	%	Nature and Extent of Economic Regulation: Sales To Ultimate Consumers	Wholesale Sales: Auth	Govt	POUs	IOUs
5	Illinois	30	3,070	1.94	Not regulated				
	Indiana	43	4,764	3.01	Unqualified regulation			X	
	Michigan	14	1,403	0.89	Unqualified regulation	X	X	X	X
	Minnesota	50	5,865	3.70	Authority with election of cooperative				
	Ohio	28	3,458	2.18	Not regulated				
	Wisconsin	30	2,038	1.29	Regulated if coop is a utility under law	X	X	X	X
	Total	195	20,598	13.00					
6	Arkansas	20	3,913	2.47	Unqualified regulation				
	Louisiana	15	4,593	2.90	Authority with election of cooperative				
	New Mexico	17	2,115	1.34	Unqualified regulation	X	X	X	X
	Oklahoma	28	5,359	3.38	Unqualified regulation				
	Texas	82	13,975	8.82	Unqualified regulation	X	X	X	X
	Total	162	29,955	18.91					
7	Iowa	52	2,833	1.79	Unqualified regulation				
	Kansas	37	2,831	1.79	Unqualified regulation	X	X	X	X
	Missouri	47	5,749	3.63	Not regulated				
	Nebraska	35	297	0.19	Not regulated				
	Total	171	11,710	7.39					
8	Colorado	24	4,567	2.88	Unqualified regulation	X	X	X	X
	Montana	25	1,645	1.04	Not regulated				
	North Dakota	27	2,749	1.74	Not regulated				
	South Dakota	34	1,753	1.11	Not regulated				
	Utah	5	1,175	0.74	Unqualified regulation	X	X	X	X
	Wyoming	14	2,712	1.71	Unqualified regulation	X	X	X	X
	Total	129	14,601	9.22					

Table 3.10 (Continued)

Region	State	Number of Cooperatives	1984 Sales (In Gwh) Amount	%	Nature and Extent of Economic Regulation: Sales To Ultimate Consumers	Wholesale Sales: Auth	Govt	POUs	IOUs
9	Arizona	11	1,527	0.96	Unqualified regulation	X	X	X	X
	California	5	181	0.11	Not regulated				
	Hawaii	0	0	0.00	Not regulated				
	Nevada	8	299	0.19	Service to non-members is regulated	X	X	X	X
	Total	24	2,007	1.27					
10	Alaska	15	2,270	1.43	Deregulated upon vote of 15% of members	X	X	X	X
	Idaho	9	1,031	0.65	Not regulated				
	Oregon	15	2,320	1.46	Not regulated				
	Washington	16	1,426	0.90	Not regulated				
	Total	55	7,047	4.45					
	US Total	991	158,401	100.00					

SOURCE: National Association of Regulatory Utility Commissioners, 1984 Annual Report on Utility and Carrier Regulation, Rural Electrification Administration, 1984 Statistical Report, Rural Electric Borrowers, and data provided by the Edison Electric Institute.

Auth - Public Authorities
Govt - U.S. Government
POUs - Publicly Owned Electric Utilities
IOUs - Investor-Owned Electric Utilities

X - Denotes that state has regulatory jurisdiction.

listed in Table 3.10 excludes a cooperative in Puerto Rico with an outstanding loan from REA.

Table 3.10 shows that only 46 states have RECs in existence. The states of Massachusetts, Connecticut, Rhode Island, and Hawaii have not enacted legislation enabling formation of RECs. The majority of cooperatives are located in five federal regions--Regions 4, 5, 6, 7, and 8. The state of Texas with 82 cooperatives has the largest number.

In contrast to state-level regulation of state/municipal electric systems (Table 3.3), Table 3.10 shows that the extent of state-level jurisdiction over the rates established by cooperatives is much more extensive. Twenty of the 46 state regulatory bodies had unconditional jurisdiction over the end-use rates of RECs. In 1984, those 20 states accounted for 42.3 percent of total cooperative end-use sales and 401 of the 991 cooperatives that had loans outstanding with REA. On the other hand, 20 states, accounting for 44.6 percent of total cooperative end-use sales and 456 cooperatives, did not have regulatory jurisdiction over RECs.

In addition to those 40 states, the states of Florida, Minnesota, Wisconsin, Louisiana, Nevada, and Alaska have some degree of economic regulatory authority over cooperatives. Florida has authority to regulate the structure of REC rates. In Minnesota, the REC is under the jurisdiction of the PUC if it opts to be placed under state regulation. RECs in Wisconsin come under state jurisdiction if the cooperative becomes a public utility as defined under Wisconsin statute. In Nevada, if the cooperative provides electricity to customers other than members of the cooperative, those sales come under state-level purview. Finally, cooperatives can choose to be regulated in Louisiana and can choose not to be regulated in Alaska.

Therefore, authority for cooperative pricing is lodged at three different levels. REA has overall responsibility to ensure the financial soundness of the cooperatives. At the state level, 20 states have economic jurisdiction over the cooperative. For those cooperatives not under state regulatory jurisdiction, the level of prices and rate structure is individually determined in the context of meeting REA policy with respect to financial soundness.

3.5.2. Depreciation

Since, in general, cooperatives are not subject to Federal income taxes, accelerated cost recovery for tax depreciation purposes is not applicable. For book depreciation purposes, the useful lives of various classes of assets do not differ from those used by investor-owned utilities and the provision for depreciation is generally on a straight-line basis.

3.5.3. Taxation

As non-profit business firms, RECs are exempt from Federal profits taxes. The exemption is applicable if at least 85 percent of their revenues are derived from electricity sales to members of the cooperative. If, in any one tax year, the revenue constraint is violated, the cooperative is subject to Federal profits taxes in that year. Additionally, cooperatives are subject to state and local taxes--other than income taxes--as are investor-owned utilities.

Table 3.11 presents the amount of taxes reported by cooperatives, their total revenues, and the percentage of revenues accounted for by taxes for distribution borrowers, power supply borrowers, and in total by Federal region. Table 3.11 shows that, in the aggregate across all cooperatives, 2.03 percent of operating revenues were expended on various forms of taxes in 1984. Distribution borrowers expended 2.08 percent and power supply borrowers 1.95 percent.

At the regional level, distribution borrowers in Region 2 expended the largest percentage of revenues on taxes, while those in Region 6 the least. For power supply borrowers, there is only one cooperative in Region 1. It did not report any taxes in 1984. There were no power supply borrowers in Region 2. The lone power supply borrower in Region 10--Pacific Northwest Generating Co. in Oregon--accounted for the largest portion of revenues expended on taxes for power supply borrowers across regions.

3.5.4. Construction Work in Progress

Power supply borrowers--numbering 63 of the 992 active borrowers in 1984--are the major focus of discussion of ratemaking treatment of Construction Work in Progress (CWIP) for cooperatives. This is attributable to the nature of their construction expenditures which, in general, are characterized by relatively more lengthy construction periods and relatively more costly generation and transmission construction programs. An allowance for funds used during construction--or, alternatively, capitalized interest--is generally not computed for construction programs of relatively short duration with modest cost that would characterize the construction programs of distribution borrowers.

Table 3.11
Rural Electric Cooperatives
Tax Payments
Dollar Amounts and Percentage of Revenues
By Federal Region
1984

(Dollar Amounts in Thousands)

Region	Distribution Borrowers			Power Supply Borrowers			Total-All Borrowers		
	Revenues	Taxes	%	Revenues	Taxes	%	Revenues	Taxes	%
1	56,500	1,793	3.17	6,701	0	0.00	63,201	1,793	2.84
2	15,258	1,345	8.82	0	0	0.00	15,258	1,345	8.82
3	532,731	10,124	1.90	312,314	3,795	1.22	845,045	13,919	1.65
4	3,876,110	70,051	1.81	2,198,151	30,874	1.40	6,074,261	100,925	1.66
5	1,516,274	47,702	3.15	1,234,720	35,843	2.90	2,750,994	83,545	3.04
6	2,239,413	37,100	1.66	1,265,178	16,893	1.34	3,504,591	53,993	1.54
7	988,109	17,870	1.81	984,704	14,092	1.43	1,972,813	31,962	1.62
8	898,162	21,383	2.38	1,049,805	32,216	3.07	1,947,967	53,599	2.75
9	201,272	3,754	1.87	125,694	6,115	4.86	326,966	9,869	3.02
10	488,066	13,560	2.78	12,999	680	5.23	501,065	14,240	2.84
Total	10,811,895	224,682	2.08	7,190,266	140,508	1.95	18,002,161	365,190	2.03

SOURCE: Computed from Rural Electrification Administration, 1984 Statistical Report, Rural Electric Borrowers.

To illustrate this point, power supply borrowers accounted for 99 percent of the $1,245.4 million in total AFUDC credits reported by all cooperatives in 1984. Additionally, as of December 31, 1984, power supply borrowers accounted for nearly 95 percent of the $10,106.1 million of CWIP reported by the cooperatives.

As with state/municipal electric systems, it is very difficult to generalize about the treatment of CWIP and associated AFUDC credits for ratemaking purposes across all cooperatives. However, an indication of that treatment for power supply borrowers is provided in REA's annual report, Statistical Report, Rural Electric Borrowers. Table 3.12 provides a summary of information on AFUDC credits and average CWIP balances for power supply borrowers in 1984 by Federal region. Additionally, the effective rate of capitalized interest is provided. It is calculated as the quotient of reported AFUDC credits and average CWIP balances.[13]

Table 3.12 shows that the majority of construction activity for power supply borrowers in 1984 was concentrated in Regions 4, 5, 6, and 8. Region 2 has no power supply borrowers which explains the zero balance. The lone power supply cooperative in each of Regions 1, 9, and 10 had very little construction activity in 1984.

Although only a gross approximation, the effective rates of capitalized interest presented in Table 3.12 seem to indicate that, in

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[13]Calculation of an effective rate of capitalized interest in this manner is a gross approximation to the actual approach typically used. In general, the cost of funds used for a construction program--in the case of cooperatives, typically debt--is applied to monthly CWIP balances, not average beginning-of-year and end-of-year balances.

Table 3.12
Rural Electric Cooperatives
Allowance for Funds Used During Construction (AFUDC)
and
Average Construction Work in Progress (CWIP)
By Federal Region
1984

(Dollar Amounts in Thousands)

Region	AFUDC		Average CWIP*		Effective Rate
	Amount	%	Amount	%	
1	2,216	0.2	24,637	0.2	9.0
2	0	0.0	0	0.0	0.0
3	28,119	2.3	234,961	2.3	12.0
4	498,609	40.8	4,623,681	44.6	10.8
5	209,174	17.1	1,640,659	15.8	12.7
6	226,162	18.5	1,781,252	17.2	12.7
7	44,334	3.6	231,731	2.2	19.1
8	213,416	17.5	1,824,382	17.6	11.7
9	127	0.0	2,095	0.0	6.1
10	0	0.0	5	0.0	0.0
Total	1,222,157	100.0	10,363,401	100.0	11.8

SOURCE: Compiled from Rural Electrification Administration, 1984 Statistical Report, Rural Electric Borrowers.

*Computed as simple average of beginning-of-year and end-of-year balances.

general, power supply borrowers capitalize the cost of funds used for construction--usually debt financing--and reflect that amount as a credit to current period income. The capitalized borrowing cost then becomes a part of the cost of the construction program.

3.6. FEDERAL POWER PROJECTS

3.6.1. Regulation

Federal power operations are divided into two segments: (1) five Power Marketing Agencies (PMAs) and (2) the Tennessee Valley Authority (TVA). The PMAs include the Bonneville Power Administration (BPA), the Alaska Power Administration (APA), the Western Area Power Administration (WAPA), the Southwestern Power Administration (SWPA), and the Southeastern Power Administration (SEPA). TVA is a government corporation and relatively more autonomous than the PMAs with respect to rate determination. Its rate level and rate structure are set internally, outside the purview of Federal and state regulatory bodies. The rate structures and rate levels of the five PMAs, however, are reviewed and approved by Federal authorities.

Prior to enactment of the Department of Energy Organization Act in August of 1977, the Federal Power Commission had final approval over the level and structure of rates of BPA, SEPA, SWPA, and APA. WAPA was created in December, 1977 pursuant to the Department of Energy's enabling legislation.

Enactment of the DOE Organization Act created the Federal Energy Regulatory Commission (FERC) and gave DOE primary responsibility for reviewing and approving rates of the PMAs. Under provisions of the

Pacific Northwest Electric Power Planning and Conservation Act in 1980, however, authority for the review and approval of the rates of the Bonneville Power Administration was given to FERC. Subsequently, with promulgation of Delegation Order No. 0204-108 in December, 1983, the Secretary of Energy delegated final ratemaking review and approval authority for APA, SWPA, SEPA, and WAPA. Under the order, the administrators of those four PMAs were given the authority to develop power and transmission rates for their respective service areas. The Deputy Secretary of Energy was given responsibility for approving and placing in effect <u>on an interim basis</u> the rates submitted by the PMA administrators. FERC, in turn, was delegated authority either (a) to approve and place in effect <u>on a final basis</u> or (b) to disapprove the rates given interim approval by the Deputy Secretary of Energy. Under the delegation order, the authority for development of rates for short-term sales of power on a final basis was given to the administrators of the four PMAs. A short-term power sale is defined as one that does not exceed one year.

If an interim rate is placed into effect and subsequently disapproved by FERC, DOE is obligated to develop a different rate structure within a 120-day period. During the period of time that a new rate structure is being developed, the rate structure initially established by the Deputy Secretary stays in effect. Other features of the delegation order provide for compensation in the event that the revised rates approved by the commission are lower than the interim rates.

Under provisions of the Pacific Northwest Electric Power Planning and Conservation Act, BPA has authority to set rates for general requirements and direct service industrial customers. Also, if deemed necessary, special rates for low system density customers can be provided. The establishment of rates requires a notice in the Federal register, hearings, oral and written comments, and ultimate approval by FERC. Approval by FERC is limited to determining that (1) revenues generated by the implementation of the rate structure will be sufficient to repay the Federal investment in the system over a reasonable period of time, (2) rates are based on the total cost of operating the system, and (3) rates are divided equitably between Federal and non-Federal users of the transmission system.

The remainder of this section will address pricing or ratemaking for the PMAs and TVA and financial issues. Financial issues include depreciation policy, taxation, and the ratemaking treatment of Construction Work in Progress (CWIP).

3.6.2. Pricing

The federal government has a dual personality with respect to determining rates for PMAs. On one hand, its role is similar to a banker--not unlike the relationship of a private financial institution to an investor-owned utility. In this capacity, the primary consideration is repayment of its investment in generation and transmission facilities. On the other hand, the Federal government is the owner of the power systems and is concerned with cost minimization on the systems.

Rates are determined in PMAs through a complicated process involving a yearly Federal investment repayment study. Briefly, PMAs are required to set rates to ensure coverage of operation and maintenance expenses (including depreciation), the cost of purchased power, and debt service. The priority of payment of expenses is in the same order. The annual rate studies determine potential adjustments to the rate level. Future O&M expenses and purchased power costs are estimated for a five-year period and then are assumed to remain constant after this period for 45 years. For debt service coverage, a constant repayment schedule is computed for each project so that all of the Federal government's investment in generation facilities is paid back within 50 years and, for the investment in transmission facilities, within 35 to 45 years.

The three categories of expenditure (O&M expenses, purchased power, and debt service) are summed for each year and divided by estimated electric generation to determine the cost per kWh for that year. Rates for the ensuing year are based on this repayment study. For the following year, another repayment study is undertaken and the rates determined from that study may differ from those determined in the prior year's study. Thus, the rates that are in effect in a given period are directly the result of the rate study conducted in the previous period only--not to other rate studies that may have been performed in the past.

The method of forecasting future O&M expenses and the cost of purchased power substantially complicates determining rate levels. It is assumed that future years will be <u>average</u> water years and the estimates of electricity generation, the cost of purchased power, and associated O&M expenses are based on this assumption. The use of an average water year as the basis of forecasting generation, purchased power, and O&M expenses implies that revenues actually generated are seldom the same as those forecasted. Half of the time, yearly revenues do not cover actual costs and, the other half of the time, there is a surplus of revenues over costs. If revenues exceed costs, the surplus (net margin or net income) is used to repay the principal of the government's investment. In deficit years, if revenue is sufficient to cover O&M expenses, the cost of purchased power, and interest charges, principal payments are deferred until future years. Under this circumstance, the next repayment study is based on the total amount of principal outstanding at the time that the repayment study is conducted, irrespective of deficiencies in repaying the Federal investment. However, if revenue is insufficient to cover O&M expenses, purchased power, and interest charges, the deficit (in the form of a Federal government advance) must be repaid first the next year. Principal that has been repaid in the past cannot be reborrowed to fund deficits.

In contrast to the PMA's pricing scheme, TVA's overall ratemaking guideline is to maintain rates as low as possible consistent with satisfying three tests to ensure financial stability. The pricing structure of TVA is not intended to earn a specific return on invested capital in its electric system (retained earnings and the investment of the federal government). Therefore, TVA's pricing process is similar to the rate-setting process of municipally owned systems that do not necessarily price to maximize profit subject to a return on invested capital.

The foundation for ratemaking is the determination of operating expenses and capital charges. Total electric operating expenses are simply the sum of operation expenses (including the cost of purchased power), maintenance expenses, depreciation and amortization, and payments in lieu of taxes. Capital charges are comprised of a credit for AFUDC, interest on long-term debt, a predetermined amount of surplus or retained earnings to be used in operations, and the repayment of the federal government's investment. Interest on long-term debt and repayment of the federal government's investment in TVA are the subject of Chapter 4, while the calculation of AFUDC is discussed below.

Given this background on operating costs, the rate level is set to satisfy three minimum financial conditions that are intended to ensure financial stability. If the tests are not satisfied, the rate level is increased. The tests are related to the credit taken for AFUDC and the amount of net margin or net income that is generated in any one year.

The first financial condition, the cash flow test, requires that revenues are large enough at least to cover operation and maintenance expenses (excluding depreciation and amortization expenses), "tax" payments, repayment of the appropriate amount to the Federal government on its investment in the electric system, net interest charges, and an amount the Board of TVA deems necessary as a margin for reinvestment in the electric system. Since net interest is included, AFUDC, which is an income credit and does not generate a current cash flow, is included as a reduction in expenses on the cost side of the test. However, depreciation and amortization, which are non-cash charges, are excluded. In effect, then, the cash flow test requires that the non-cash charge for depreciation/amortization be equal to the non-cash credit for AFUDC. This procedure is in contrast to that used by IOUs where the non-cash credit for AFUDC is a function of the amount of CWIP allowed in the rate base by the regulatory body and the applicable AFUDC rate.

The second financial condition involves the total net margin or net income to be generated (the earnings test). The test requires that net income must at least equal the total return on the Federal government's investment in power operations during successive five-year periods. This requirement ensures that retained earnings are not decreased at the end of the five-year period.

The third financial condition is the bonds test which is a more stringent version of the earnings test and, in general, accomplishes the same objective. The bonds test requires that, during running five-year periods, net income must be at least as high as the total repayment (interest and principal) that would have been made on the appropriated investment of the Federal government if no payment had been made on the principal since 1961. In essence, this test maintains the original Federal investment by replacing it with retained earnings.

3.6.3. Depreciation

Since Federal power projects are not subject to Federal profits taxes, the issues of tax normalization or flow-through of federal tax benefits of accelerated cost recovery are not applicable. For "book" purposes, the annual provision for depreciation differs for PMAs and TVA.

TVA uses the straight-line depreciation method for recovering the cost of fixed investment. The procedure results in equal annual charges for depreciation expense over the estimated useful life of the assets used in providing electricity. PMAs, on the other hand, use the compound interest method for computing the annual depreciation charge. Although the two methods result in the same nominal dollar depreciation charge over the life of the asset, charges in the earlier years of an asset's life under the compound interest method are less than under the straight-line approach. For later years, they are greater than the straight-line approach. The reason for the difference is that, under the compound interest method, the annual charges are assumed to be placed in a "fund" and earn interest over the estimated useful life of the assets. Interest rates vary from PMA to PMA and from asset to asset.

Additionally, PMAs set revenues to recover the cost of the Federal government's investment in generation and transmission facilities within a 50-year period. Depreciation for financial accounting purposes, however, is based on the estimated useful lives of the assets. For generating capacity, estimated lives extend up to 100 years. Therefore, revenues are based on recovering costs of generating investment over shorter periods of time than those assets are depreciated and included in operating expenses. The practice violates standard accounting procedure where revenues are supposed to be matched with costs.

3.6.4. Taxation

Federal power projects are not subject to Federal, state, or local taxation in a manner similar to IOUs. The PMAs not only do not make jurisdictional tax payments but they do not make in lieu of tax payments either. Congress has, however, authorized one-time payments to local governments from time to time as compensation for impacts of Federally owned transmission facilities.

TVA, on the other hand, makes in-lieu-of-tax payments to states and counties in which it operates. The total amount of expenditures on "taxes" in any given year is equal to 5 percent of the previous year's operating revenues derived from the sale of electricity--excluding revenues derived from electricity sales to Federal agencies.

3.6.5. Construction Work in Progress

All of the Federal power projects follow the practice of capitalizing interest during construction [computing an Allowance for Funds Used During Construction (AFUDC) as a non-cash income credit]. The practices, however, differ somewhat between PMAs and TVA. Briefly, PMAs impute AFUDC for construction projects (in general, for production facilities since the lead times for construction of transmission facilities are much shorter) and, as in the case of IOUs, the amount of cumulative AFUDC imputed over the construction period becomes a part of the cost of the asset. Since AFUDC reduces the total interest charge for PMAs, and PMAs price to recover all costs, the effect of capitalizing interest is much the same as an IOU not being allowed to incorporate CWIP in the rate base. That is, the capital charge for construction projects is recouped from ratepayers when the project is placed "on line" and the AFUDC, which is one component of the cost of the project, is depreciated.

While TVA follows the same procedure, there is a constraint imposed on the total amount of AFUDC credited to income each year. The constraint, under the cash flow test, is the amount of non-cash charges to income (depreciation and amortization, for example) less repayment of the federal investment in any given year.

4. COMPARATIVE FINANCIAL PERFORMANCE ACROSS OWNERSHIP TYPES

4.1. INTRODUCTION

The purpose of this chapter is to compare the financial performance of investor-owned electric utilities (IOUs), state/municipal electric systems, rural electric cooperatives (RECs), and Federal power projects. The chapter is divided into two sections. The first section presents a comparison of the annual operating results of the various ownership types over the 1979 to 1984 period. Besides nominal levels of revenue and expenditure, operating results as a percentage of revenues and on a unit sales basis for the ownership types are compared. The second section provides a comparison of capital structure, sources and cost of capital, and interest coverage for the ownership types in the industry.

There is no comprehensive source of financial information for all of the electric utilities that comprise each of the ownership types in the industry. As noted in Chapter 2, the Edison Electric Institute publishes the most comprehensive array of data on the U.S. electric utility industry, but the only financial information presented in its annual statistical report is for investor-owned utilities. Therefore, multiple sources of data were used for the comparison. Besides the Edison Electric Institute, sources include annual publications of the Energy Information Administration, the Rural Electrification Administration, and individual annual reports of Federal power projects.

A number of problems arise in comparing the financial performance of electric utilities on an ownership basis. They include different accounting systems, different fiscal years, intercompany transactions, and, as discussed in the previous chapter, different pricing strategies. Each of the problems will be discussed in turn.

First, utilities of various ownership types are not required to use the same accounting system. "Major" investor-owned electric utilities[1] and Federal power projects are required to use the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts designed in concert with the National Association of Regulatory Utility Commissioners (NARUC). The reporting system of rural electric cooperatives generally conforms to the Uniform System of Accounts with minor adjustments made for peculiarities that exist in the operation of the cooperatives. State/municipal utilities are not required to conform to the Uniform System of Accounts. However, based on examination of the annual reports of 39 of the largest state/municipal systems, it is concluded that at least the largest systems conform to the Uniform System of Accounts. Also, because the comparison of financial data is at an aggregated level, any differences in accounting systems should not invalidate conclusions drawn from the comparison.

Second, electric utilities of the various ownership types do not report on the basis of the same fiscal year. Therefore, aggregated results of the various ownership types for any specific year reflect different periods of operation. For comparative purposes over time,

[1]Prior to 1984, investor-owned electric utilities were classified as "Class A and Class B" and "Class C and Class D" by the Federal Energy Regulatory Commission (FERC). Inclusion in one of the two broad classes was based on the amount of annual operating revenues generated by the utilities. In 1984, however, FERC issued Order No. 390 in Docket No. RM83-66-000 which changed the Class A and Class B and Class C and Class D categories to "Major" and "Non-Major," respectively. Under provisions of the order, classification of individual utilities into one of the two categories is based on energy sales or transmission services.

however, problems with lack of consistency in reporting periods are mitigated because individual utilities generally report annual operating results on the basis of the same 12-month period from year to year.

Third, simple aggregation of the operating results of a group of utilities of the same ownership type will result in double-counting. This problem results from transactions between any two utilities that comprise an ownership aggregate. For example, simple aggregation of the operating results of two utilities where one of the utilities sold power to the other at wholesale would result in overstatement of both operating revenues and the cost of purchased power. Thus, for an accurate portrayal of a "composite" company by ownership type, intercompany transactions must be eliminated. Intercompany transactions have been eliminated in the financial comparisons presented below.

Finally, as the discussion in the previous chapter emphasized, utilities of different ownership types have different pricing strategies. Because of the imposition of economic regulation by state-level regulatory authorities, investor-owned utilities set rates to generate revenues that (a) cover the costs of operation--operation and maintenance expenses, depreciation, and taxes--and (b) compensate the various contributors of capital--bondholders, preferred shareholders, and equity owners. In general, the concept of rate base plays no role in ratemaking for publicly owned utilities. Their pricing strategy is to generate revenues that will attain a sufficiently large interest coverage ratio. In the discussion below, different ratemaking strategies are significant factors in explaining differences in financial performance across ownership types.

4.2. COMPARATIVE OPERATING RESULTS

Tables 4.1 through 4.4 contain the nominal operating results and total sales volume for investor-owned electric utilities (IOUs), state/municipal systems, rural electric cooperatives (RECs), and Federal power projects, respectively, for the years 1979 through 1984. Data for each of the composite ownership types presented in the tables do not include all of the utilities that comprise each ownership category. While the data for IOUs, RECs, and Federal projects are nearly comprehensive, the data for state/municipal systems include only 162 of the largest systems (161 for 1980). In 1984, these 162 systems accounted for approximately 52 percent of end-use sales volume.

For IOUs, EIA publishes company-specific and aggregate operating results in its annual report Financial Statistics of Selected Electric Utilities (prior to 1982, Statistics of Privately Owned Electric Utilities in the United States). In the publication, the reporting companies comprise nearly 100 percent of the investor-owned electric utility industry. However, in the process of aggregating the operating results of the individual companies, no attempt is made to eliminate intercompany transactions. The aggregate results, therefore, do not represent consolidated financial statements in the technical accounting sense. The Edison Electric Institute (EEI) in its annual Statistical Yearbook does present a consolidated statement of income with intercompany transactions eliminated. The EEI data for the years 1979 through 1984 are presented in Table 4.1.

The only published financial data for state/municipal electric systems that is consistent over time is EIA's annual report Financial Sta-

Table 4.1
Investor-Owned Electric Utilities
Operating Results
1979-1984

(Dollar Amounts in Millions)

Category	1979	1980	1981	1982	1983	1984
Revenues	68,152	80,636	94,270	101,693	109,446	120,090
O&M Expenses:						
Production	32,575	40,396	47,281	48,010	48,408	52,288
Transmission/Distribution	3,360	3,761	4,172	4,721	5,143	5,614
Customer Accounts	1,641	1,894	2,254	2,621	2,867	3,128
Sales	45	33	31	34	37	47
Administrative/General	3,759	4,373	5,104	5,855	6,437	7,084
Total O&M	41,380	50,457	58,842	61,242	62,892	68,161
Depreciation/Amortization	5,706	6,193	6,893	7,588	8,370	9,249
Taxes	9,127	10,268	12,195	14,604	17,523	19,884
Operating Margin	11,939	13,718	16,347	18,258	20,658	22,796
Sales Volume (In tWh)	1719.6	1732.6	1745.2	1701.0	1749.9	1841.0

SOURCE: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1979-1984.

Table 4.2
State/Municipal Electric Systems
Operating Results
1979-1984

(Dollar Amounts in Millions)

Category	1979	1980	1981	1982	1983	1984
Revenues	5,896	7,045	8,116	9,395	10,111	11,089
O&M Expenses:						
Production	3,148	4,055	4,693	5,283	5,609	6,066
Transmission/Distribution	414	464	530	604	658	704
Customer Accounts	101	112	130	152	161	173
Sales	19	21	28	30	31	30
Administrative/General	288	369	398	568	611	733
Total O&M	3,969	5,022	5,780	6,635	7,070	7,706
Depreciation/Amortization	440	497	578	728	771	867
Taxes	147	169	209	230	250	280
Operating Margin	1,338	1,357	1,549	1,801	2,020	2,236
Sales Volume (In tWh)	223.5	233.9	232.9	243.3	246.1	261.8

SOURCE: Energy Information Administration, Statistics of Publicly Owned Electric Utilities, 1979-1981; Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1982-1984; and individual EIA-412 annual reports of state/municipal electric systems.

Table 4.3
Rural Electric Cooperatives
Operating Results
1979-1984

(Dollar Amounts in Millions)

Category	1979	1980	1981	1982	1983	1984
Revenues	5,760	6,874	8,262	9,653	10,985	12,095
O&M Expenses:						
Production	3,159	3,847	4,616	5,142	5,757	6,356
Transmission/Distribution	479	560	635	728	771	853
Customer Accounts	192	224	260	293	311	330
Sales	8	7	8	8	8	10
Administrative/General	399	459	522	598	653	717
Total O&M	4,237	5,097	6,041	6,769	7,501	8,266
Depreciation/Amortization	501	589	685	803	906	1,009
Taxes	196	220	254	294	339	365
Operating Margin	826	968	1,281	1,787	2,240	2,455
Sales Volume (In tWh)	149.6	159.8	167.3	172.4	185.5	207.1

SOURCE: Rural Electrification Administration, Statistical Report, Rural Electric Borrowers, 1979-1984.

Table 4.4
Federal Power Projects
Operating Results
1979-1984

(Dollar Amounts in Millions)

Category	1979	1980	1981	1982	1983	1984
Revenues	3,227	4,043	4,795	5,625	6,329	7,552
O&M Expenses:						
Production	NA	NA	NA	NA	NA	NA
Transmission/Distribution	NA	NA	NA	NA	NA	NA
Customer Accounts	NA	NA	NA	NA	NA	NA
Sales	NA	NA	NA	NA	NA	NA
Administrative/General	NA	NA	NA	NA	NA	NA
Total O&M	2,073	2,474	2,955	3,423	3,766	4,598
Depreciation/Amortization	224	236	266	301	326	504
Taxes	100	114	138	164	165	170
Operating Margin	830	1,219	1,436	1,737	2,072	2,280
Sales Volume (In tWh)	235.8	240.2	238.8	253.7	261.3	287.7

SOURCE: Southeastern Power Administration, Annual Report, 1979-1984; Tennessee Valley Authority, Power Program Summary, 1979-1984; Southwestern Power Administration, Annual Report, 1979-1984; Bonneville Power Administration, Program and Financial Summary, 1979-1984; and Western Area Power Administration, Annual Report, 1979-1984.

NA - Not Available

tistics of Selected Electric Utilities (prior to 1982, Statistics of Publicly Owned Electric Utilities). However, the report only includes data for large-volume, state/municipal systems. As with investor-owned utilities, no attempt is made in the EIA publication to eliminate inter-company transactions among the utilities that comprise the aggregate. However, the annual reports for each of the individual companies reporting wholesale electric sales were examined to determine the volume of sales and associated revenues that were transacted with other utilities that comprise the aggregate. Sales between utilities were eliminated from total sales. Revenues from these sales were subtracted from operating revenues and the cost of purchased power. In 1984, of the 104,890 gigawatt-hours of wholesale sales reported by all state/municipal systems in the Financial Statistics of Selected Electric Utilities, 15.4 percent were eliminated as transactions between individual systems comprising the aggregate. The corresponding percentages for 1979 through 1983 were 16.5, 14.8, 16.3, 17.9, and 16.4 percent, respectively.

The Rural Electrification Administration publishes annual statistics on RECs. The annual report includes statistics on both distribution and power supply borrowers for individual cooperatives and in the aggregate. Since REA's reporting system also includes data on inter-cooperative transactions, it is possible to compute aggregate operating results for the cooperatives over the 1979-1984 period that are consolidated in the technical accounting sense. In 1984, of the 341,124 gigawatt-hours of total sales reported by distribution and power supply borrowers, 39.3 percent were between individual cooperatives. The corresponding percentages for 1979 through 1983 were 38.5, 38.4, 38.4, 38.9, and 38.2 percent, respectively.

Data for Federal power projects in Table 4.4 were compiled by aggregating the individual annual reports submitted by the projects to the Secretary of the Department of Energy. The 1980 and 1981 annual reports for the Alaska Power Administration (APA) were not available. For consistency across years, APA's operating results were not included for any of the years.[2] Operating results for the Western Area Power Administration include only its transmission activities and not the consolidated results for both transmission and production of hydroelectric power by the U.S. Army Corps of Engineers and the Water and Power Resources Service in the West. Although they represent a negligible amount of sales, interproject sales among the Federal systems also were compiled and eliminated.

Therefore, the sales volume for each individual ownership type presented in Tables 4.1 through 4.4 represents (a) the total amount of retail sales by the individual ownership types and (b) wholesale sales to utilities other than those included in the composite ownership category. The financial information in the tables reflects operating results for only those sales. There is significant variation in the sectoral composition of sales for each ownership type. While the majority of sales by Federal power projects are made at wholesale, for example, they are incorporated in the analysis because they were transacted with different ownership categories.

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[2]Exclusion of the Alaska Power Administration does not materially affect the operating results for federal power projects. In 1983, for example, APA reported $4.5 million of revenues which represents 0.07 percent of the total revenues of federal power projects.

Table 4.5 presents the percent composition of operating revenues--or, alternatively, the distribution of the revenue-dollar--by ownership type for the years 1979 through 1984. The data was calculated from the nominal operating results in Tables 4.1 through 4.4. The data contained in Table 4.5 underscore the differences in the operations of IOUs in comparison with publicly owned systems. In 1984, for example, nearly $0.70 of every dollar of revenue generated by state/municipal systems and RECs was accounted for by operation and maintenance expenditures in comparison with $0.57 for IOUs. For the most part, this difference is attributable to different degrees of exposure to taxes. As discussed in Chapter 3, IOUs are subject to Federal taxation while, in general, the utilities that comprise the other organizational types are not. From Table 4.5, taxes accounted for 16.6 cents of the revenue-dollar of IOUs in 1984--more than six times larger than that of state/municipal systems and more than five times that of RECs.

Among the various categories of O&M expenditures, a number of factors account for differences across ownership types. One of the primary differences is generation mix across ownership types. As discussed in Chapter 2, more than 83 percent of the generating capacity of IOUs is accounted for by conventional steam in comparison with less than 62 percent for state/municipal systems. Nearly 60 percent of the generating capacity of Federal power projects is accounted for by hydroelectric power. Another source of disparity for the various ownership types is their sources of purchased power. State/municipal systems and cooperatives are given preference to purchase the relatively less expensive power generated from Federal hydroelectric projects.

Table 4.5
Percent Composition of Operating Revenues
U.S. Electric Utility Industry
By Ownership Type
1979-1984

(In Percentages)

Category	1984				1983				1982			
	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects
Revenues	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
O&M Expenses:												
Production	43.5	54.7	52.6	NA	44.2	55.5	52.4	NA	47.2	56.2	53.3	NA
Transmission/Distribution	4.7	6.3	7.1	NA	4.7	6.5	7.0	NA	4.6	6.4	7.5	NA
Customer Accounts	2.6	1.6	2.7	NA	2.6	1.6	2.8	NA	2.6	1.6	3.0	NA
Sales	0.0	0.3	0.1	NA	0.0	0.3	0.1	NA	0.0	0.3	0.1	NA
Administrative/General	5.9	6.6	5.9	NA	5.9	6.0	5.9	NA	5.8	6.0	6.2	NA
Total O&M	56.7	69.5	68.4	60.9	57.5	69.9	68.3	NA	60.2	70.6	70.1	60.9
Depreciation/Amortization	7.7	7.8	8.3	6.7	7.6	7.6	8.2	5.2	7.5	7.7	8.3	5.4
Taxes	16.6	2.5	3.0	2.2	16.0	2.5	3.1	2.6	14.4	2.4	3.0	2.9
Operating Margin	19.0	20.2	20.3	30.2	18.9	20.0	20.4	32.7	18.0	19.2	18.5	30.9

Table 4.5 (Continued)

Category	1981 Investor-Owned Utilities	1981 State/Local Systems	1981 Rural Electric Coops	1981 Federal Power Projects	1980 Investor-Owned Utilities	1980 State/Local Systems	1980 Rural Electric Coops	1980 Federal Power Projects	1979 Investor-Owned Utilities	1979 State/Local Systems	1979 Rural Electric Coops	1979 Federal Power Projects
Revenues	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
O&M Expenses:												
Production	50.2	57.8	55.9	NA	50.1	57.6	56.0	NA	47.8	53.4	54.8	NA
Transmission/Distribution	4.4	6.5	7.7	NA	4.7	6.6	8.1	NA	4.9	7.0	8.3	NA
Customer Accounts	2.4	1.6	3.1	NA	2.3	1.6	3.3	NA	2.4	1.7	3.3	NA
Sales	0.0	0.3	0.1	NA	0.0	0.1	0.3	NA	0.1	0.3	0.2	NA
Administrative/General	5.4	4.9	6.3	NA	5.4	5.2	6.7	NA	5.5	4.9	6.9	NA
Total O&M	62.4	71.2	73.1	61.7	62.6	71.3	74.1	61.2	60.7	67.3	73.6	64.3
Depreciation/Amortization	7.3	7.1	8.3	5.5	7.7	7.1	8.6	5.8	8.4	7.5	8.7	6.9
Taxes	12.9	2.6	3.1	2.9	12.7	2.4	3.2	2.8	13.4	2.5	3.4	3.1
Operating Margin	17.3	19.1	15.5	29.9	17.0	19.3	14.1	30.1	17.5	22.7	14.3	25.7

SOURCE: Calculated from Tables 4.1 through 4.4.

NA--Not Available

Another difference between the organizational types is the extent to which they transmit and distribute power. The cooperatives, for example, were originally organized to distribute power in relatively isolated rural areas. In comparison with IOUs, the miles of distribution line per customer is significantly larger. An indication of the effect of distributing power in relatively less populous areas is provided in Table 4.5. In comparison with IOUs and state/municipal systems, a larger fraction of the RECs' revenue-dollar is accounted for by transmission/distribution costs. A total of 7.1 cents of every dollar of revenue was accounted for by transmission/distribution costs for RECs in comparison with 4.7 cents for IOUs and 6.3 cents for state/municipal systems in 1984.

Conceptually, the nominal value of the operating margin is the amount of revenues allocated to various contributors of capital--bondholders, preferred shareholders, and equity owners for IOUs and bondholders and equity for publicly owned systems.[3] One of the most salient aspects of the data presented in Table 4.5 is the near equality of the portion of the revenue-dollar accounted for by the operating margin of IOUs, state/municipal systems, and cooperatives in 1984. The relatively large share of the revenue-dollar accounted for by the operating margin of Federal power projects in 1984 (30.2 percent from Table 4.5) is attributable to TVA. TVA's operating margin accounted for 37.7 percent of revenues in 1984. Excluding TVA, Federal power projects' operating margin was 19.4 percent of revenues in 1984. An in-depth discussion of the reasons for that difference will be provided in the next section.

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[3]The sources and composition of capital will be discussed in detail in the next section.

With the exception of state/municipal systems, the percentage of operating revenues accounted for by the operating margin increased from 1979 to 1984 for all ownership types. For IOUs, the increase from 17.5 percent in 1979 to 19.0 percent in 1984 is attributable to large increases in compensation to equity capital. For state/municipal systems, the decline is attributable to the opposite effect. For cooperatives, increasing interest payments for long-term debt--accounted for by power supply borrowers primarily--are the reason for the increase in operating margin from 14.3 percent in 1979 to 20.3 percent in 1984. For Federal power projects, increasing returns for equity-supported investment are the reason for the increase in operating margin from 25.7 percent in 1979 to 30.2 percent in 1984.[4]

Another interesting comparison of operating performance among ownership types is revenues on a per-unit sales basis. Table 4.6 presents that comparison for the years 1979 through 1984. The information in Table 4.6 was computed by dividing the nominal operating results contained in Tables 4.1 through 4.4 by the sales volume presented at the bottom of those tables. As noted above, the sales volume reflects the total sales made by the ownership types (including wholesale sales) less the amount to other utilities contained within the respective ownership types.

As would be expected, revenue per kWh sales is highest for IOUs in all years under consideration. Revenue/kWh increased from 3.96 cents/kWh in 1979 to 6.52 cents/kWh in 1984. For the most part, the increase

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[4]A thorough discussion of the return on equity for the ownership types is presented in the next section.

Table 4.6
Operating Results Per Unit Sales
U.S. Electric Utility Industry
By Ownership Type
1979-1984

(In Cents per Kilowatt-Hour)

Category	1984				1983				1982			
	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects
Revenues	6.52	4.24	5.84	2.62	6.25	4.11	5.92	2.42	5.98	3.86	5.60	2.22
O&M Expenses:												
Production	2.84	2.32	3.07	NA	2.77	2.28	3.10	NA	2.82	2.17	2.98	NA
Transmission/Distribution	0.31	0.27	0.41	NA	0.29	0.27	0.42	NA	0.28	0.25	0.42	NA
Customer Accounts	0.17	0.07	0.16	NA	0.16	0.07	0.17	NA	0.15	0.06	0.17	NA
Sales	0.00	0.01	0.00	NA	0.00	0.01	0.00	NA	0.00	0.01	0.00	NA
Administrative/General	0.38	0.28	0.35	NA	0.37	0.25	0.35	NA	0.34	0.23	0.35	NA
Total O&M	3.70	2.94	3.99	1.60	3.59	2.87	4.04	1.44	3.60	2.73	3.93	1.35
Depreciation/Amortization	0.50	0.33	0.49	0.17	0.48	0.31	0.49	0.12	0.45	0.30	0.47	0.12
Taxes	1.08	0.11	0.18	0.06	1.00	0.10	0.18	0.06	0.86	0.09	0.17	0.06
Operating Margin	1.24	0.85	1.18	0.79	1.18	0.82	1.21	0.79	1.07	0.74	1.04	0.68

Table 4.6 (Continued)

Category	1981				1980				1979			
	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects	Investor-Owned Utilities	State/Local Systems	Rural Electric Coops	Federal Power Projects
Revenues	5.40	3.49	4.94	2.02	4.65	3.01	4.30	1.70	3.96	2.64	3.85	1.38
O&M Expenses:												
Production	2.71	2.02	2.76	NA	2.33	1.73	2.41	NA	1.89	1.41	2.11	NA
Transmission/Distribution	0.24	0.23	0.38	NA	0.22	0.20	0.35	NA	0.20	0.19	0.32	NA
Customer Accounts	0.13	0.06	0.16	NA	0.11	0.05	0.14	NA	0.10	0.05	0.13	NA
Sales	0.00	0.01	0.00	NA	0.00	0.01	0.00	NA	0.00	0.01	0.01	NA
Administrative/General	0.29	0.17	0.31	NA	0.25	0.16	0.29	NA	0.22	0.13	0.27	NA
Total O&M	3.37	2.48	3.61	1.24	2.91	2.15	3.19	1.04	2.41	1.78	2.83	0.89
Depreciation/Amortization	0.39	0.25	0.41	0.11	0.36	0.21	0.37	0.10	0.33	0.20	0.33	0.10
Taxes	0.70	0.09	0.15	0.06	0.59	0.07	0.14	0.05	0.53	0.07	0.13	0.04
Operating Margin	0.94	0.67	0.77	0.60	0.79	0.58	0.60	0.51	0.69	0.60	0.55	0.35

SOURCE: Calculated from Tables 4.1 through 4.4.

NA--Not Available

is attributable to higher production costs, depreciation charges, and taxes.

The lowest unit revenue was experienced by Federal power projects. The most significant contributing factor to this is the relatively low O&M expenses attributable to heavy reliance on hydroelectric power production. In 1984, for example, per-unit O&M expenses for RECs were nearly three times the corresponding amount for Federal power projects.

One of the contributing factors to the cooperatives' relatively large unit O&M expenditures is transmission and distribution costs. In 1984, for example, RECs' unit transmission and distribution costs were 0.10 cents/kWh greater than the next largest ownership type (IOUs). The differences for other years are similar. Another factor that accounts for the disparity in the unit O&M expenses of RECs is their relatively large production costs (where production costs include the cost of purchased power). In 1984, for example, unit production costs for RECs were 0.23 cents/kWh greater than that of IOUs.

4.3. SOURCES AND COST OF CAPITAL AND COMPARATIVE INDICATORS OF PERFORMANCE

As with all business entities, electric utilities finance their operations through internally generated funds or external sources of funds. Internal sources of funds for IOUs include net income, depreciation and amortization, and provisions for deferred income taxes and deferred investment tax credits. External sources of funds include debt (both short- and long-term), common stock, and preferred stock. Constraints on the internal generation of funds are manifested in the return allowed the IOU on its invested capital, while constraints on both the level and composition of external funding are imposed both by the regulatory body and financial markets.

Publicly owned electric utilities, on the other hand, derive their internal funds from net income and depreciation/amortization since, in general, they are not subject to Federal taxation. As discussed in detail below, external funding sources for publicly owned utilities are limited to the investment of a governmental body and an array of public financial institutions and private capital markets.

Table 4.7 presents the percentage composition of capital by ownership type during 1984. The percentage accounted for by each type of capital was computed as the ratio of the average beginning-of-year and end-of-year balance to average total capitalization. Table 4.7 shows that a little less than 50 percent of the IOUs' total capital was accounted for by long-term debt at the end of 1984. This contrasts markedly with the corresponding percentages for publicly owned utilities. For state/municipal systems, RECs, and Federal projects, the respective percentages were 67.9 percent, 84.6 percent, and 92.6 percent.

The remainder of the IOUs' capital structure was composed of preferred stock (10.7 percent) and common equity (41.2 percent). The equity portion of capital for IOUs is composed of the par value of outstanding stock, the premium on common and preferred stock, retained earnings, and other paid-in capital.

The equity portion of state/municipal systems' capital structure (32.1 percent of total capital) is composed of retained earnings and the contribution of the state or municipality to the utility. That contri-

Table 4.7
Capital Structure
U.S. Electric Utility Industry
By Ownership Type
1984 Average

(In Percentages)

Capital Type	Investor-Owned Utilities	State/Municipal Systems	Rural Electric Coops	Federal Power Projects
Long-Term Debt	48.1	67.9	84.6	92.6
Preferred Stock	10.7	0.0	0.0	0.0
Equity	41.2	32.1	15.4	7.4
Total Capitalization	100.0	100.0	100.0	100.0

SOURCE: Computed from Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1984; Rural Electrification Administration, Statistical Report, Rural Electric Borrowers, 1984; Southeastern Power Administration, Annual Report, 1984; Tennesse Valley Authority, Power Program Summary, 1984; Southwestern Power Administration, Annual Report, 1984; Bonneville Power Administration, Program and Financial Summary, 1984; and Western Area Power Administration, Annual Report, 1984.

bution is composed of the actual investment of the municipality in the utility and a constructive surplus or deficit. The latter amount represents the net value of services contributed to the utility by the governing authority. Less than five percent of the total equity of state/municipal systems is accounted for by the contribution of political jurisdictions. The remainder is accounted for by retained earnings.

RECs' equity capital (15.4 percent of total capitalization in Table 4.7) is composed of retained earnings and the investment (membership) of the participants in the cooperative. The retained earnings portion of equity reflects patronage capital and other equity of the firms. Patronage capital is simply the accumulated profit of the cooperatives that is required to be distributed to the participants in the cooperative over some reasonable period of time. Thus, it represents the undistributed earnings of the cooperatives and is similar to the retained earnings of an investor-owned utility. More than 98 percent of the average equity capital for RECs in 1984 was attributable to retained earnings.

The composition of total capital for RECs in Table 4.7 reflects the aggregation of distribution borrowers and generation and transmission borrowers (power supply borrowers). For distribution borrowers alone, the percentage of average capitalization attributable to long-term debt was only 64.3 percent in 1984. The applicable percentage for generation and transmission borrowers was 95.9 percent. The power supply construction programs of generation and transmission borrowers are financed almost exclusively from REA-insured and REA-guaranteed long-term debt.

As discussed in detail below, the equity portion of Federal power projects' capitalization (7.4 percent) consists exclusively of retained earnings. TVA's percentage of capital attributable to equity was 9.6 percent in 1984. The corresponding percentage for Federal Power Marketing Agencies (PMAs) was 4.2 percent.

Although not shown in Table 4.7, the percentage of capitalization attributable to debt for IOUs and state/municipal systems has declined since 1979. For IOUs, the percentage has declined from 50.2 percent in 1979, while the corresponding percentage for state/municipal systems was 72.0 percent in 1979. For cooperatives, the percentage has increased from 81.1 percent in 1979 to 84.6 percent in 1984. For Federal power projects, the increase has been from 88.6 percent in 1979 to 92.6 percent in 1984.

Table 4.8 presents a comparison of capital sources across ownership types. For both IOUs and state/municipal systems, a source of debt capital is capital markets. However, whereas the interest payments on debt issued by IOUs are subject to Federal taxation, interest payments on municipal debt issues are exempt from Federal taxation. Additionally, for some IOUs that are divisions or subsidiaries of a larger corporate entity (e.g., holding companies, horizontally integrated energy firms), a source of debt financing may be an advance or loan from the corporate parent. In this case, the debt service charge may not necessarily reflect market-determined interest rates.

For IOUs, equity is derived from both investors and ratepayers. Investors, operating through capital markets, are a source of equity capital for IOUs through the purchase of ownership shares in the utility. Investors are not necessarily ratepayers of the utility. Through purchases of electricity, ratepayers contribute revenue to the utility. The portion of that revenue not used for (1) payment of operating expenses and (2) compensation to capital contributors (bond- and stockholders) is a source of equity capital (earned surplus or retained earnings).

Table 4.8
Sources of Capital
U.S. Electric Utility Industry
By Ownership Type

Capital Type	Investor-Owned Utilities	State/Municipal Systems	Rural Electric Coops	Federal Power Projects
Debt Capital	Capital Markets	Capital Markets	REA	FFB
			CFC	Federal Approp.
	Corporate Parent		BFC	
	Other		FFB	
Equity Capital	Ratepayers	Ratepayers	Ratepayers	Ratepayers
	Investors	Taxpayers	Members	

REA - Rural Electrification Administration
CFC - National Rural Utilities Cooperative Finance Corporation
FFB - Federal Financing Bank
BFC - Bank for Cooperatives

State/municipal systems derive their equity capital from ratepayers through earned surplus and from taxpayers through the governing body. If a municipal system distributes electricity only within the confines of its incorporated area, the ratepayers of the system can be considered its stockholders. That is, since ratepayers are taxpayers and a portion of taxes may have been used to fund the utility, the ratepayers may be considered owners of the utility. Under this characterization, the only source of equity capital for the municipality is the taxpayer.

Sources of debt financing for RECs include the Rural Electrification Administration (REA), the National Rural Utilities Cooperative Finance Corporation (CFC), the Federal Financing Bank (FFB), the Bank for Cooperatives (BFC), and other miscellaneous banks. Originally, with creation of the REA in 1935, REA-insured loans were advanced to groups of farmers who desired central station electric service at interest rates that reflected the cost of money to the government. Enactment of the Pace Act in 1944 established the interest rate on REA-insured loans at 2 percent with a 35-year maturity period. That rate of interest was maintained for nearly 30 years.

REA was designed to act as a credit agency to ensure the electrification of rural America. REA-insured loans, therefore, were advanced primarily to construct and operate electric distribution systems. As originally conceived, REA-financed distribution cooperatives would be given preference for power produced at Federal dams or would purchase power from local investor-owned electric utilities. The policy of REA was to advance funds for construction of generation and transmission (G&T) facilities only if a cooperative did not have a source of wholesale power or if the price of wholesale power was greater than the cooperative's estimated cost of generation. REA's policy on the provision of G&T loans changed in 1961. Funds were now advanced for the construction of generation and transmission facilities when generation was seen as necessary for the effectiveness and security of a cooperative.

Partially as a result of REA's change in policy on G&T loans and the realization that REA could not provide all of the cooperatives' financing needs, alternate sources of financing for cooperatives were developed. In 1969, the RECs formed the National Rural Utilities Cooperative Finance Corporation (CFC). The CFC, organized as a financial intermediary, gives RECs the ability to "pool" their borrowing needs. The CFC sells financial obligations in capital markets and, in turn, uses the proceeds to advance loans to cooperatives who are a part of its membership. The interest on the loans advanced to the CFC from private market sources is subject to Federal taxation for the investors.

In 1973, the Rural Electrification Act was amended. Under provisions of the amendment, the interest rate on REA-insured loans was increased from 2 percent to 5 percent except for borrowers who met the limiting criteria for 2 percent loans established by the amendment. The amendment also established the Rural Electrification and Telephone Revolving Fund (RETRF) from which REA-insured loans would be advanced. The amendment also authorized REA to guarantee loans made by other lenders to the cooperatives.

In 1974, the FFB and REA established a relationship where the FFB agreed to provide debt financing to RECs where the debt instruments were guaranteed by REA. The interest rate on FFB obligations is determined on each individual issue and is based on the cost of money to the Federal government. Besides REA-insured and REA-guaranteed loans, RECs can also borrow money without REA guarantee. The amount of those loans, however, is nominal.

The equity portion of capital for RECs is derived from purchasers of electricity and the members (or owners) of the cooperative. Here again, if the REC distributes electricity only to members of the cooperative, the members and ratepayers are equivalent.

All Federal power projects--the five PMAs (and associated generating facilities) and TVA--have been financed, at least in part, by congressional appropriations. Also, TVA is allowed to finance its power operations from long-term securities issued with the FFB up to a statutory ceiling. The present ceiling is $30 billion. The Bonneville Power Administration (BPA), with enactment of the Federal Columbia River Transmission System Act in 1974, is authorized to issue similar notes with the FFB to finance expansion and improvement of its transmission system in the Northwest. The interest rate on the notes issued with FFB reflects the cost of money to the Federal government.

The investment of the Federal government through the congressional budgetary process must be repaid to the U.S. Treasury over the estimated life of the projects at interest rates that do not necessarily reflect the cost of money to the U.S. government. The interest rate is determined by law, administrative order, or administrative policies. Recently, it has been set at the cost of borrowing to the Federal government at the time the project is placed in service. Thus, the investment of the U.S. government in Federal power projects through the Congressional appropriation process can be viewed as "pseudo-debt." In Table 4.7, the net investment of the Federal government and TVA's and BPA's borrowing from the FFB have been combined and categorized as long-term debt to compute the percentage of capital accounted for by debt. The equity of Federal projects includes only the retained earnings or accumulated savings of the power projects.

Table 4.9 presents the effective or average long term rate of interest of the various ownership types for the years 1979 through 1984.

Table 4.9
Average Long-Term Interest Rate
U.S. Electric Utility Industry
By Ownership Type
1979-1984

(In Percentages)

Ownership Type	1979	1980	1981	1982	1983	1984
Investor-Owned Utilities	7.60	8.14	8.91	9.30	9.45	9.67
State/Municipal Systems	4.45	5.25	5.62	5.93	6.52	7.00
Rural Electric Cooperatives (RECs):						
Distribution Borrowers	3.76	4.06	4.44	4.59	4.79	5.07
Power Supply Borrowers	6.84	7.85	9.41	10.41	9.85	9.37
Weighted Total - RECs	5.56	6.40	7.70	8.60	8.40	8.20
Federal Power Projects (FPPs):						
Marketing Agencies	3.12	3.21	3.32	3.59	3.77	3.92
TVA	7.89	8.61	9.47	10.34	10.49	10.51
Weighted Total - FPPs	5.33	5.92	6.66	7.46	7.70	7.76

SOURCE: Computed from Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1982-1984, Statistics of Privately Owned Electric Utilities in the United States, 1978-1981, and Statistics of Publicly Owned Electric Utilities in the United States, 1978-1981; Rural Electrification Administration, Statistical Report, Rural Electric Borrowers, 1978-1984; Southeastern Power Administration, Annual Report, 1978-1984; Tennessee Valley Authority, Power Program Summary, 1978-1984; Southwestern Power Administration, Annual Report, 1978-1984; Bonneville Power Administration, Program and Financial Summary, 1978-1984; and Western Area Power Administration, Annual Report, 1978-1984.

The values represent the ratio of interest payments on long-term debt to the beginning-of-year and end-of-year average of long-term debt outstanding. The rates presented in Table 4.9 are intended to serve as surrogate or proxy values for the embedded cost of debt for the respective years. Data limitations preclude calculation of the embedded cost of debt because data are not available on proceeds from debt issued by ownership type, refinancing of issues, and the like.

As would be expected from the preceding discussion on sources of debt financing, IOUs have the highest effective cost of debt compared with the other three ownership types as a whole. State/municipal systems, utilizing tax-free municipal bonds as their primary financing instrument, have a significantly less effective cost of debt over the six-year period than the other three ownership types in total.

When RECs and Federal projects are disaggregated, however, another result emerges. TVA's effective cost of debt was higher than that of IOUs over the six-year period and REC power supply borrowers had a higher effective cost in 1981, 1982, and 1983. This result is directly attributable to the temporal composition of debt issues. That is, a larger percentage of total outstanding debt of TVA and REC power supply borrowers is comprised of more recent, relatively higher-interest issues.

Between rural electric cooperative types, distribution borrowers have the lowest cost of debt. The reason is the composition of long-term debt for the two types of cooperatives. In 1984, for example, of the $10.5 billion of outstanding long-term debt for distribution borrowers, a little less than 80 percent was comprised of REA-insured loans.

As noted above, until 1973 those loans were advanced at an interest rate of 2 percent and from that time the interest rate has been 5 percent. On the other hand, less than 11 percent of the power supply borrowers' outstanding long-term debt in 1984 was composed of REA-insured loans. Loans not insured by REA are issued at higher rates of interest.

As shown in Table 4.9, the effective cost of debt for PMAs and TVA varies markedly. As noted above, with the exception of the Bonneville Power Administration's authority to borrow from the FFB to expand and improve its transmission system, the PMAs' debt is composed of the Federal government's net investment in the power projects at interest rates that do not necessarily reflect market-determined interest rates or the cost of money to the Federal government. TVA's primary source of debt, on the other hand, is the FFB which sets interest rates to reflect the cost of money to the Federal government.

In contrast to determining the cost of debt, the cost of equity capital for the various ownership types presents significantly more complex problems. In the ratemaking process, the cost of equity for IOUs can be estimated using a number of different approaches. Once a return is computed, it is used in concert with the cost of the other components of capital to determine both the nominal compensation to contributors of capital and revenue requirements. Formally, revenue requirements can be expressed as follows:

$$RR = OE + (dD + pP + eE)\ (RB)\ , \tag{1}$$

where RR = Required revenues,
OE = Operating expenses (O&M expenses, depreciation, taxes),
d = Cost of debt,
p = Cost of preferred stock,
e = Allowed return on equity,

D = Percentage of capital attributable to debt,
P = Percentage of capital attributable to preferred stock,
E = Percentage of capital attributable to equity,
RB = Rate base.

The return on invested capital (or the rate base) is a weighted average of the costs of the different components of capital. From (1), the nominal dollar value compensation for equity-supported investment of IOUs can be expressed as follows:

$$RR - [OE - (dD + pP)(RB)] = (eE)(RB) \quad . \tag{2}$$

As discussed in the previous chapter, the concept of rate base does not, in general, play a role in the determination of rate levels for publicly owned systems. However, publicly owned systems do face a financial constraint in the form of the interest coverage ratio. That is, they must price electricity at a level that covers operating expenses and debt service charges, with a net margin that generates a sufficiently high interest coverage ratio. Conceptually, interest coverage measures the number of times a firm "turns over" its fixed interest charges and, as such, provides an indication of the ability of a firm to meet its debt service obligations.

Therefore, the ratemaking formula for publicly owned utilities can be defined as follows:

$$RR = h(OE + dD^*) \quad , \tag{3}$$

where h = Interest coverage ratio,
D^* = Amount of debt,

and RR, OE, and d are defined in equation (1). From (3), the nominal dollar equity return can be expressed as follows:

$$RR - (OE + dD^*) = (h-1)(OE + dD^*) \ . \tag{4}$$

From the left-hand terms in (2) for investor-owned utilities and (4) for publicly owned systems, the compensation for equity-supported investment can be calculated by subtracting compensation for the use of capital other than equity from operating income. The earned rate of return on equity is then simply calculated as the ratio of compensation for equity capital to equity-supported investment.

The amount of operating income attributable to debt and preferred stock for IOUs is calculated by applying the cost of debt and preferred stock to debt-supported and preferred stock-supported investment, respectively. The cost of debt and preferred stock was approximated as the ratio of interest expense and preferred dividends to average debt and preferred stock outstanding, respectively. For publicly owned systems, the cost of debt was calculated in a manner similar to that of IOUs. The effective or average cost of debt was provided in Table 4.9.

Capital-supported investment by type of capital is calculated by applying average capitalization percentages (beginning-of-year and end-of-year simple averages) to average utility plant used in providing electricity. For the average utility plant of IOUs, the ratemaking process was approximated by computing a "formulistic" rate base. That is, since the operating income of IOUs represents the nominal compensation to capital contributors--bond-holders, preferred shareholders, and equity owners--and regulatory practices differ on what is included in the rate base to compute the compensation, a surrogate rate base across utilities was developed to capture the major components of a rate base. It was calculated as net utility plant in service (including net nuclear fuel), less deferred taxes, plus an allowance for working capital. The working capital allowance was approximated by taking one-eighth of O&M expenses excluding purchased power. For publicly owned systems, the invested capital--or "rate base"--is simply net utility plant in service.

A complication arises in using this procedure to calculate the amount of operating income attributable to equity-supported investment for IOUs. Equation (2) shows that the amount of operating income attributable to equity is total operating income less the amount attributable to debt- and preferred stock-supported investment. However, a portion of total operating income is also attributable to a current return for Construction Work in Progress (CWIP) included in the rate base.[5] Therefore, calculating the amount of operating income attributable to equity by subtracting debt and preferred stock portions from total operating income would overstate the amount of equity-supported operating income.

To remedy this problem, the amount of Allowance for Funds Used During Construction (AFUDC) for both debt and other funds was incorporated in the return-on-equity calculation. The computation involved three steps. First, the amount of compensation for debt and preferred stock and the amount of debt-, preferred stock-, and equity-supported investment were derived from a rate base without CWIP included. Second, the amount of AFUDC for debt along with debt-supported and equity-

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[5]As discussed in Chapter 3, the amount of CWIP allowed in the rate base varies across state-level regulatory jurisdictions.

supported CWIP were computed.[6] Third, the realized return on equity-supported investment was computed as the ratio of (a) total capital compensation--operating income plus AFUDC-Debt and AFUDC-Equity--less (1) compensation for debt (debt on debt-supported investment without CWIP and AFUDC-Debt) and (2) compensation for preferred stock to (b) equity-supported investment--equity without CWIP and the equity portion of CWIP.

For publicly owned systems, the complication does not arise. AFUDC is generally capitalized for construction programs and, therefore, a current return for CWIP is not included in operating income. Thus, net utility plant in service was used as the amount of invested capital to compute the earned return on equity.[7]

Table 4.10 presents the results for the computation of earned return on equity across ownership types for the years 1979 through 1984. The earned return on equity for IOUs and REA-financed distribution borrowers was the most stable over the six-year period. IOUs experienced a steady growth over the period and, with the exception of 1981, distribution borrowers did also. The earned return for state/municipal systems declined for two years after 1979, increased significantly in 1982, and declined in the two most recent years. The negative earned return on equity for power supply borrowers indicates generation of an

[6]Note here that the total of CWIP attributable to electricity operations is divided between debt-supported and equity-supported portions. The division was based on the average amount of debt and equity outstanding during the year. The preferred stock portion of capital was not considered part of the computation.

[7]The treatment of CWIP by state/municipal systems, rural electric cooperatives, and Federal power projects was discussed in Chapter 3 on pp. 3-51 to 3-57, pp. 3-64 to 3-68, and p. 3-76, respectively.

Table 4.10
Earned Return on Equity
U.S. Electric Utility Industry
By Ownership Type
1979-1984

(In Percentages)

Ownership Type	1979	1980	1981	1982	1983	1984
Investor-Owned Utilities	12.16	12.78	14.17	15.33	16.85	17.24
State/Municipal Systems	18.42	16.53	17.21	18.72	18.15	16.70
Rural Electric Cooperatives (RECs):						
Distribution Borrowers	9.23	9.29	8.59	11.58	14.57	14.85
Power Supply Borrowers	21.43	(17.88)	(23.57)	(23.29)	(0.34)	(11.25)
Weighted Total - RECs	9.39	5.51	2.81	4.73	11.05	10.39
Federal Power Projects (FPPs):						
Marketing Agencies	(4.90)	5.46	0.07	(21.50)	40.73	71.16
TVA	45.52	88.05	141.32	171.90	144.39	139.97
Weighted Total - FPPs	19.44	42.51	63.22	75.38	84.52	92.12

SOURCE: Computed from Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1982-1984, Statistics of Privately Owned Electric Utilities in the United States, 1978-1981, and Statistics of Publicly Owned Electric Utilities in the United States, 1978-1981; Rural Electrification Administration, Statistical Report, Rural Electric Borrowers, 1978-1984; Southeastern Power Administration, Annual Report, 1978-1984; Tennesse Valley Authority, Power Program Summary, 1978-1984; Southwestern Power Administration, Annual Report, 1978-1984; Bonneville Power Administration, Program and Financial Summary, 1978-1984; and Western Area Power Administration, Annual Report, 1978-1984.

operating margin insufficient to cover interest charges on debt-supported investment in electric plant.

Federal power marketing agencies' earned return fluctuated widely over the six-year period. As discussed in the previous chapter, this is attributable in large measure to rates based on average water years for hydroelectric generation. The prolific increase in TVA's earned return on equity-supported investment over the six-year period is attributable to pricing to recoup losses associated with deferred or cancelled nuclear generating units. The amounts written off to recoup the losses were \$400.0 million, \$256.6 million, \$204.2 million, and \$800.0 million in the years 1981, 1982, 1983, and 1984, respectively.

A financial indicator of paramount importance to the investment community--and one that plays a significant role in determining the cost of debt in financial markets--is the interest coverage ratio. Table 4.11 contains values for the interest coverage ratio in the electric utility industry by ownership type for the years 1979 through 1984. Interest coverage is defined here as the ratio of electric operating income to interest expense on debt-supported investment in electric utility plant. The selection of this particular definition of coverage compares after-Federal tax coverage of IOUs with the coverage of publicly owned systems that are not, in general, subject, to federal income taxes.

The coverage ratios contained in Table 4.11 for IOUs and state/municipal systems are based on electric utility operations only. That is, for utilities that are combination companies (provide multi-utility ser-

Table 4.11
Interest Coverage Ratios
U.S. Electric Utility Industry
By Ownership Type
1979-1984

Ownership Type	1979	1980	1981	1982	1983	1984
Investor-Owned Utilities	2.54	2.57	2.62	2.72	2.96	3.04
State/Municipal Systems	2.61	2.19	2.15	2.22	2.21	2.13
Rural Electric Cooperatives (RECs):						
Distribution Borrowers	2.23	2.11	1.91	2.19	2.53	2.63
Power Supply Borrowers	1.13	0.91	0.92	0.92	1.00	0.95
Weighted Total - RECs	1.39	1.18	1.07	1.09	1.23	1.23
Federal Power Projects (FPPs):						
Marketing Agencies	0.87	1.12	1.00	0.76	1.40	1.79
TVA	2.05	2.59	2.71	2.58	2.46	2.41
Weighted Total - FPPs	1.47	1.80	1.81	1.72	1.85	1.95

SOURCE: Computed from Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1982-1984, Statistics of Privately Owned Electric Utilities in the United States, 1978-1981, and Statistics of Publicly Owned Electric Utilities in the United States, 1978-1981; Rural Electrification Administration, Statistical Report, Rural Electric Borrowers, 1978-1984; Southeastern Power Administration, Annual Report, 1978-1984; Tennessee Valley Authority, Power Program Summary, 1978-1984; Southwestern Power Administration, Annual Report, 1978-1984; Bonneville Power Administration, Program and Financial Summary, 1978-1984; and Western Area Power Administration, Annual Report, 1978-1984.

vices), only the results attributable to electric operations are included.

Table 4.11 shows that, with the exception of 1979, IOUs had the largest interest coverage ratio over the 1979-1984 time period. REC power supply borrowers had the lowest coverage over the period. One explanation of the low coverage ratios for power supply borrowers is their insulation from the need to attract funding from capital markets.

Taken in tandem, Tables 4.7, 4.10 and 4.11 illustrate the effects of debt leverage on the performance of privately and publicly owned utilities. As noted in Table 4.7, publicly owned systems are relatively more leveraged than privately owned systems. The larger the share of capitalization attributable to debt, the larger the return on equity needed to attain a predetermined coverage ratio. State/municipal systems in 1984, for example, experienced an 18.15 percent return on equity in comparison to 16.85 percent for IOUs. Their coverage ratio, however, was 2.21 in comparison with 2.96 for IOUs. The difference, of course, can be explained by the fact that debt accounted for 48.7 percent of IOUs' capitalization in 1983, while the corresponding percentage for state/municipal systems was 69.7 percent.

5. CONCLUSION

The purpose of this report was to discuss regulatory, financial, and economic issues associated with publicly owned electric utilities in the United States and to compare and contrast their operation and performance with investor-owned electric utilities. The public portion of the U.S. electric utility industry was defined as (1) state/municipal systems (state projects, county projects, public utility districts, joint action agencies, and municipally owned utilities), (2) rural electric cooperatives, and (3) Federal power projects. While rural electric cooperatives are not technically publicly owned utilities, they were included as part of the public segment of the industry because of three characteristics: (1) exemption from Federal taxation, (2) access to relatively less expensive power produced at Federal dam sites and (3) relatively less costly sources of debt financing.

Publicly owned utilities accounted for 23.4 percent of the 672,462 megawatts of total electric generating capacity in 1984. Of that total, state/municipal systems, rural electric cooperatives, and Federal power projects owned 10.3 percent, 3.7 percent, and 9.4 percent, respectively. While publicly owned systems owned less than one-fourth of total capacity in 1984, they accounted for 73.0 percent of the 4,841 megawatts of total internal combustion capacity and 67.6 percent of the 80,590 megawatts of total hydroelectric capacity. The former amount is primarily attributable to state/municipal systems which owned 65.9 percent of total U.S. internal combustion capacity, while the latter is primarily attributable to Federal power projects which accounted for 46.1 percent of total U.S. hydroelectric capacity.

Publicly owned systems accounted for 24.0 percent of total end-use sales in 1984. State/municipal systems, rural electric cooperatives, and Federal power projects sold 14.5 percent, 6.9 percent, and 2.6 percent of the U.S. total, respectively. The relatively small percentage of end-use sales by Federal projects--five Federal power marketing agencies and the Tennessee Valley Authority--in comparison with capacity (9.4 percent in 1984) is explained by their role as power generators and transmitters of electricity for wholesale sales. On the other hand, rural electric cooperatives had 3.7 percent of capacity in 1984 with 6.9 percent of end-use sales. This is attributable to power purchased by distribution borrowers in excess of power generated by power supply borrowers.[1]

Public power is most prevalent in the eight states that comprise Federal region 4 and the four states that comprise federal region 10.[2] In 1984, public power accounted for 40.2 percent of total end-use sales in region 4 and 56.4 percent of total end-use sales in region 10. The reason for the relatively large amount of public power in region 4 is the Tennessee Valley Authority which produces, transmits, and sells power to municipally owned utilities and cooperatives in six of the eight states of region 4 and the state of Virginia in region 3. Similarly, the Bonneville Power Administration produces and transmits a

[1]The distinction between a distribution borrower and a power supply (or generation and transmission) borrower is made by the Rural Electrification Administration (REA). The former type of cooperative is advanced loans by REA primarly to distribute power, while guaranteed or insured loans are made to the latter primarily for power generation and transmission purposes.

[2]The eight states that comprise region 4 include Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee. Region 10 is composed of the states of Alaska, Idaho, Oregon, and Washington.

large amount of power for sale at wholesale to publicly owned utilities in region 10.

For the United States as a whole, the average price of end-use electricity obtained by investor-owned utilities in 1984 was 6.53 cents per kilowatt-hour (kWh).[3] The corresponding average price for publicly owned systems was 5.28 cents/kWh. The difference between the average price of investor-owned utilities and publicly owned systems is largest in the two states that comprise region 2 (New York and New Jersey). In 1984, investor-owned utilities in that region obtained 9.60 cents/kWh for end-use electricity sales, while publicly owned systems charged 4.56 cents/kWh for end-use sales. The reason for the difference is the New York Power Authority which produces hydroelectric power and transmits it for sale at wholesale to publicly owned distributors in the region. Other regions with large differences between the investor-owned segment and the publicly owned segment include the four states that comprise region 9 (7.78 cents/kWh to 5.25 cents/kWh) and the four states of region 10 (4.26 cents/kWh to 2.90 cents/kWh).

Chapters 3 and 4 of this report addressed some reasons for the differences in the average price of electricity between publicly owned and privately owned systems. The emphasis in those chapters was not on differences attributable to generation mix, input prices, and the like, but rather on sources and cost of capital, taxation, and regulatory issues (differential economic regulation across ownership types and the treatment of construction work in progress, as examples) that have a marked

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[3]Average price is the ratio of end-use electricity revenues to end-use electricity sales.

impact on differences in electricity rates and financial performance of investor-owned and publicly owned electric systems.

Publicly owned electric systems have access to relatively less expensive sources of debt financing in comparison with investor-owned systems. State/municipal systems issue tax-free debt which systematically has a lower debt service cost than the debt of investor-owned systems. Rural electric cooperatives have access to relatively less costly debt guaranteed and insured by REA. Federal power projects have received congressional appropriations for investment in power production and transmission facilities that historically have not reflected prevailing interest rates. Additionally, TVA--and under more recent legislation, the Bonneville Power Administration--have access to funds of the Federal Financing Bank which are issued at the cost of money to the Federal government.

While the lack of published data precludes computation of the embedded or marginal cost of debt across ownership types in the industry, some insight can be gained by comparison of the average long-term interest rate of privately owned and publicly owned utilities.[4] In 1984, the average long-term interest rate for investor-owned systems was 9.67 percent in comparison with 7.00 percent, 8.20 percent, and 7.76 percent for state/municipal systems, cooperatives, and Federal power projects, respectively.

[4]The average long-term interest rate is calculated as the ratio of long-term interest expense for a given year to the average of beginning-of-year and end-of-year long-term debt outstanding in that year.

In general, publicly owned utilities are exempt from Federal taxation. However, with the exception of the five Federal power marketing agencies, publicly owned systems are either subject to sub-Federal taxation or make in-lieu-of-tax payments. The Tennessee Valley Authority, for example, contributes five percent of prior year operating revenues to governments within their seven states of operation.

The total tax burden--actual taxes and in-lieu-of-tax payments--of state/municipal systems and rural electric cooperatives is much less in comparison with investor-owned systems. In 1984, total tax payments attributable to electric operations accounted for 15.41 percent of total electric operating revenues of investor-owned utilities. For state/municipal systems and rural electric cooperatives, the corresponding percentages were 4.89 percent and 2.03 percent, respectively.[5]

Arguments have been made that the total tax burden of investor-owned systems in comparison with publicly owned systems is misleading because of the deferral of a large portion of Federal income taxes in computing any given year's Federal income tax liability. However, the argument is not supported by the evidence. Of the 15.41 percent of operating revenues accounted for by taxes for investor-owned utilities in 1984, 6.62 percent was for non-income taxes, 0.54 percent was for other-than-Federal income taxes, and 8.26 percent was accounted for by Federal income tax provisions. Of the 8.26 percent total Federal tax provision, 2.95 percent was accounted for by a provision for current in-come taxes

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[5]The discussion of taxation includes only electric operations. Many investor-owned and municipally owned utilities are combination companies which provide more than one utility service or, in the case of investor-owned utilities, non-utility service. Taxation for other than electric operations is excluded from the discussion.

and the remaining 5.31 percent was attributable to deferred tax and deferred investment credit provisions. Excluding the latter two deferred components of 5.31 percent, the total tax burden of investor-owned systems was 10.1 percent in 1984 compared to 4.89 percent for state/municipal systems and 2.03 percent for cooperatives.[6]

With respect to the 4.89 percent of operating revenues accounted for by taxes for state/municipal systems, the analysis in Chapter 3 showed that the figure was misleading on two accounts. First, the total "tax" percentage can be divided into four components--actual tax pay-ments (1.17 percent of operating revenues), in-lieu-of-tax payments or tax equivalents (1.02 percent), contributions to general funds (2.32 percent), and net contribution of services to local governments (0.38 percent). In comparison with investor-owned utilities, if one assumes that the ratepayers of a municipally owned utility are the owners of that system in a manner similar to the stockholders of an investor-owned system, the 2.32 percent of operating revenues contributed to the general funds of local governments can be interpreted as "dividend" disbursements rather than taxes. Under this interpretation, the actual tax burden of state/municipal systems--actual taxes, in-lieu-of-tax payments, and net contributions--was only 2.57 percent of operating revenues in 1984.

Second, the analysis in Chapter 3 also showed that total tax payments of state/municipal systems was concentrated in a relatively small

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[6]A thorough discussion of deferred income tax accounting and the reason an argument can be made for excluding the deferred components of the Federal income tax provision are provided in Chapter 3.

number of systems.[7] For example, if the five largest systems making actual tax payments were excluded from the analysis, the percentage of operating revenues accounted for by actual tax payments would decline from 1.17 percent to 0.42 percent. If the ten largest were excluded, the percentage declines to 0.2 percent. Similarly, for in-lieu-of-tax payments, exclusion of the top 5 and top 10 reduces the percentage from 1.02 percent to 0.60 and 0.45 percent, respectively. For contributions to general funds of the locality, exclusion of the top 5 and top 10 reduces the percentage from 2.32 to 1.21 and 0.95 percent, respectively.

Another important difference between investor-owned and publicly owned electric systems is the degree to which they are subject to Federal- and state-level economic regulation. Investor-owned systems are, in general, subject to state-level economic regulation for end-use sales and subject to Federal regulation for wholesale sales of power. Review and final approval of the rates of the five Federal power marketing agencies are under the jurisdiction of the Federal Energy Regulatory Commission (FERC). TVA is a corporation of the Federal government and, as such, its rates are set internally, consistent with covering all power-related expenditures, without regulatory body review.

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[7]A caveat is in order here. The analysis of "tax" payments by state/municipal electric systems was based on examination of Schedule XIV of Form EIA-412, "Taxes, Tax Equivalents, Contributions, and Services During Year." A total of 162 systems were required to submit the form to the Energy Information Administration in 1984. Form EIA-412 is the only source of published information provided in sufficient detail to perform a tax analysis. The 162 systems required to submit the form are only a fraction of the more than 2,200 state/municipal systems in existence. However, they accounted for more than 52 percent of total end-use sales in 1984.

The large number of state/municipal systems and rural electric cooperatives in existence makes generalizations about regulatory authority difficult. The Federal Power Act exempted wholesale sales between state/municipal systems from Federal (FERC) jurisdiction. Similarly, a court decision exempted wholesale transactions between cooperatives from Federal jurisdiction. With respect to end-use rate regulation by state-level regulatory authorities, the analysis in Chapter 3 showed that very little of the end-use sales of state/municipal systems is subject to regulation. Ratemaking and review is generally performed by the governing body of the locality (the common council, for example) or an administrative power board either appointed by the governing body or elected by the general population. Although the degree of economic regulation by state-level regulatory bodies of cooperatives is much more extensive than that of state/municipal systems, a majority of the sales of cooperatives are not subject to state-level regulation. For both state/municipal systems and cooperatives subject to state-level economic regulation, there are indications that the type of regulation differs from the typical rate-of-return regulation imposed on investor-owned utilities.

Differences in the cost of debt, level of taxation, and extent and type of regulatory control lead to differences in the financial performance of investor-owned utilities in comparison with publicly owned systems. One of the most important measures of a utility's financial performance is the interest coverage ratio which provides an indication of the extent to which a firm is able to cover its fixed interest charges. In 1984, investor-owned utilities experienced a coverage ratio of 3.04 in comparison with 2.13 for state/municipal systems, 1.23 for cooperatives, and 1.95 for Federal power projects.

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APPENDIX A

JOINT ACTION AGENCIES

Table A.1
Joint Action Agencies
Agency Name and Location
1984

Joint Action Agency	Location
Alabama Municipal Electric Authority	Montgomery, AL
Arizona Power Pooling Association	Benson, AZ
Central California Power Agency	Sacramento, CA
M-S-R Public Power Agency	Modesto, CA
Northern California Power Agency	Roseville, CA
Southern California Public Power Authority	Glendale, CA
Southern California Utility Power Pool	Los Angeles, CA
Transmission Agency of Northern California	Sacramento, CA
Arkansas River Power Authority	Lamar, CO
Platte River Power Authority	Fort Collins, CO
Connecticut Municipal Electric Energy Cooperative	Groton, CT
Delaware Municipal Electric Corp.	Newark, DE
Florida Municipal Power Agency	Orlando, FL
Municipal Electric Authority of Georgia	Atlanta, GA
Illinois Municipal Electric Agency	Deerfield, IL
Indiana Municipal Power Agency	Indianapolis, IN
North Iowa Municipal Electric Cooperative Association	Humboldt, IO
South Iowa Municipal Electric Cooperative	Winterset, IO
Missouri Basin Municipal Electric Cooperative Association	Orange City, IO

Table A.1 (Continued)

Joint Action Agency	Location
Western Iowa Municipal Electric Cooperative Association	Manning, IO
Kansas Municipal Energy Agency	Mission, KS
Louisiana Energy and Power Authority	Lafayette, LA
Dirigo Electric Cooperative	Augusta, ME
Massachusetts Municipal Wholesale Electric Company	Ludlow, MA
Michigan Public Power Agency	Kentwood, MI
Michigan South Central Power Agency	Litchfield, MI
Northeastern Minnesota Municipal Power Agency	Hibbing, MN
Northern Municipal Power Agency	Thief River Falls, MN
Southern Minnesota Municipal Power Agency	Rochester, MN
Western Minnesota Municipal Power Agency	Ortonville, MN
Municipal Energy Agency of Mississippi	Greenwood, MS
Missouri Joint Municipal Electric Utility Commission	Columbia, MO
Nebraska Municipal Power Pool	Lincoln, NB
Municipal Energy Agency of Nebraska	Lincoln, NB
North Carolina Municipal Power Agency Number 1	Raleigh, NC
North Carolina Eastern Municipal Power Agency	Raleigh, NC
North Dakota Municipal Power Agency	Northwood, ND
American Municipal Power - Ohio	Westerville, OH
Oklahoma Municipal Power Authority	Edmond, OK
Piedmont Municipal Power Agency	Gaffney, SC

Table A.1 (Continued)

Joint Action Agency	Location
Heartland Consumer Power District	Madison, SD
Missouri Basin Municipal Power Agency	Sioux Falls, SD
South Dakota Municipal Power Agency	Sioux Falls, SD
Lone Star Municipal Power Agency	College Station, TX
Sam Rayburn Municipal Power Agency	Livingston, TX
Texas Municipal Power Agency	Bryan, TX
Intermountain Power Agency	Murray, UT
Utah Associated Municipal Power Systems	Sandy, UT
Utah Municipal Power Agency	Payson, UT
Vermont Public Power Supply Authority	Williston, VT
Central Washington Power Agency	Ellensburg, WA
Clark-Cowlitz Joint-Operating Agency	Longview, WA
Washington Public Power Supply System	Richland, WA
Badger Power Marketing Authority of Wisconsin, Inc.	Shawano, WI
Western Wisconsin Municipal Power Group	Fennimore, WI
Wisconsin Public Power Inc. System	Sun Prairie, WS
Wyoming Municipal Power Agency	Lusk, WY

SOURCE: American Public Power Association, Public Power, 1986 Directory, Washington, DC.

APPENDIX B

SAMPLE OF STATE/MUNICIPAL ELECTRIC SYSTEMS

Table B.1
Sample of State/Municipal Electric Systems
Construction Work in Progress (CWIP)
By Federal Region
1984

Federal Region	State	Electric System	CWIP ($000)
1	CT	Groton	3
1	MA	Taunton	3,437
2	NY	Jamestown	0
2	NY	New York Power Auth.	164,718
3	VA	Danville	974
4	FL	Gainesville	2,681
4	FL	Lakeland	3,578
4	FL	Orlando	152,390
4	GA	Municipal Electric Auth.	1,044,540
4	KY	Owensboro	9,345
4	SC	SC Public Service Auth.	97,503
5	MI	Lansing	8,112
6	OK	Grand River Dam Auth.	377,872
6	TX	Lower Colorado River Auth.	102,182
6	TX	San Antonio	1,004,242
7	KS	Kansas City	1,581
7	NB	Lincoln	14,393
7	NB	NB Public Power Dist.	167,902
7	NB	Omaha Public Power Dist.	56,233
8	CO	Colorado Springs	6,049
8	CO	Platte River Power Auth.	8,909
9	AZ	Salt River Project	1,597,235
9	CA	Department of Water	180,529
9	CA	Los Angeles	0
9	CA	Sacramento	422,692
9	CA	Hetch Hetchy	2,532
10	OR	Eugene	5,650
10	WA	PUD-Chelan County	16,053
10	WA	PUD-Clark County	2,578
10	WA	PUD-Cowlitz County	319
10	WA	PUD-Snohomish County	1,091
10	WA	Seattle	71,081
10	WA	Tacoma	10,523

SOURCE: Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1984, Supplementary data on individual publicly owned electric systems.

Table B.2
Sample of State/Municipal Electric Systems
Construction Work in Progress (CWIP)
By Amount of CWIP
1984

Federal Region	State	Electric System	CWIP ($000)
9	AZ	Salt River Project	1,597,235
4	GA	Municipal Electric Auth.	1,044,540
6	TX	San Antonio	1,004,242
9	CA	Sacramento	422,692
6	OK	Grand River Dam Auth.	377,872
9	CA	Department of Water	180,529
7	NB	NB Public Power Dist.	167,902
2	NY	New York Power Auth.	164,718
4	FL	Orlando	152,390
6	TX	Lower Colorado River Auth.	102,182
4	SC	SC Public Service Auth.	97,503
10	WA	Seattle	71,081
7	NB	Omaha Public Power Dist.	56,233
10	WA	PUD-Chelan County	16,053
7	NB	Lincoln	14,393
10	WA	Tacoma	10,523
4	KY	Owensboro	9,345
8	CO	Platte River Power Auth.	8,909
5	MI	Lansing	8,112
8	CO	Colorado Springs	6,049
10	OR	Eugene	5,650
4	FL	Lakeland	3,578
1	MA	Taunton	3,437
4	FL	Gainesville	2,681
10	WA	PUD-Clark County	2,578
9	CA	Hetch Hetchy	2,532
7	KS	Kansas City	1,581
10	WA	PUD-Snohomish County	1,091
3	VA	Danville	974
10	WA	PUD-Cowlitz County	319
1	CT	Groton	3
9	CA	Los Angeles	0
2	NY	Jamestown	0

SOURCE: Energy Information Administration, Financial Statistics of Selected Electric Utilities, 1984, Supplementary data on individual publicly owned electric systems.

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