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The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations

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Preface

Section 205(A)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data information program. Under this program, EIA will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information.

To assist in meeting these responsibilities, EIA has prepared this report, *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations*, which is the latest in a series of reports covering key issues in the electric power industry. This series of reports is intended for use by the U.S. Congress, Federal and State government agencies, the electric power industry, and the general public.

EIA is an independent statistical agency, and it does not advocate positions on public policy issues. Its responsibility is to provide timely, high quality information, and to perform objective, credible analyses in support of deliberations by public and private organizations. Accordingly, this report does not represent any policy positions of the U.S. Department of Energy or the Administration.

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Executive Summary

Since the passage of the Energy Policy Act of 1992, which opened the U.S. electric power industry to the start of competition,[1] investor-owned electric utilities (IOUs) have been under pressure to cut costs, to become more efficient, and to expand their products and services. Mergers, acquisitions, asset divestitures, and other forms of corporate combinations have become widespread as IOUs seek to improve their positions in the increasingly competitive electric power industry. Since 1992 IOUs have been involved in 26 mergers, and an additional 16 mergers are pending approval. One effect of these mergers is that the industry is becoming more concentrated. In 1992 the 10 largest IOUs owned 36 percent of total IOU-held generation capacity, and the 20 largest IOUs owned 56 percent of IOU-held generation capacity (Figure ES1). By 2000, the 10 largest IOUs will own an estimated 51 percent of IOU-held generation capacity, and the 20 largest will own an estimated 73 percent.

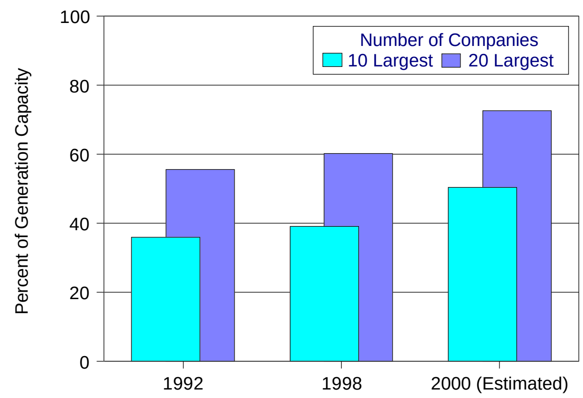
In addition to mergers within the electricity industry, IOUs, seeing growth opportunities in the natural gas industry, are merging with or acquiring natural gas companies, contributing to what is referred to as "convergence" of the two industries. Since 1997, 20 convergence mergers involving companies with assets valued at $0.5 billion or higher have been completed or are pending completion. Combining energy marketing expertise, improving access to natural gas supply, and expanding products and services are reasons most often mentioned for the mergers.

Joint ventures and strategic alliances are alternative forms of corporate combinations used to meet the challenges of competition. Many IOUs have entered into ventures or alliances with other companies to construct or purchase power plants, to purchase energy products and services, and to market energy. The benefits of these arrangements are shared risks and costs.

Influenced predominantly by State-level electricity industry restructuring programs that emphasize the unbundling of generation from transmission and distribution, and in some cases by a desire to exit the competitive power generation business, IOUs are divesting power generation assets in unprecedented numbers. Starting in late 1997 through September 1999, IOUs collectively have divested or are in the process of divesting 133.0 gigawatts of power generation capacity, representing about 17 percent of total U.S. electric utility generation capacity. Divestiture means that the IOU will either sell its generation capacity to another company or transfer the generation capacity to an unregulated subsidiary within its own holding company structure.

Most of the sold capacity has been acquired by non-utility power producers that are subsidiaries of utility

Figure ES1. Concentration of Ownership of Investor-Owned Utility Generating Capacity, 1992, 1998, and 2000



Notes: • The ten largest companies are public utility holding companies that own one or more operating electric utilities. • The 2000 data assume that all pending mergers as of September 1999 will be completed by year-end 2000. • Capacity owned by subsidiaries of IOUs was not counted when computing the rankings.

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generation Report,1992;" Form EIA-860A, "Annual Electric Generator Report - Utility,1998;" and EIA-861, "Annual Electric Utility Report (1992 and 1998)."

[1] In general, competition means that electricity prices will be based on market forces as opposed to being administratively set, and that electricity markets will be open to more power suppliers than in the past.

holding companies. For the most part, the generation assets are sold through auctions. Final selling prices have been relatively high, usually 50 to 100 percent above book value (except for nuclear power plants, which have sold for less than book value).

As a result of mergers and divestitures over the past few years, the organizational structure of the electric power industry (i.e., the numbers and roles of the industry participants) is changing. The traditional role of the electric utility as a provider of electric power is giving way to the expanding role of nonutilities as providers of electric power. An analysis of electric power data collected by the Energy Information Administration for the period 1992 through 1998 offers the following insights:

- The number of IOUs has decreased by nearly 8 percent, while the number of nonutilities has increased by over 9 percent.
- Nonutilities are expanding and buying utility-divested generation assets, causing their net generation to increase by 42 percent and their nameplate capacity to increase by 72 percent from 1992 to 1998. Nonutility capacity and generation will increase even more as they acquire additional utility-divested generation assets over the next few years.
- The nonutility share of net generation has risen from 9 percent (286 million megawatthours) in 1992 to 11 percent (406 million megawatthours) in 1998.
- Utilities have historically dominated the addition of new capacity but additions to capacity by utilities are decreasing while additions by nonutilities are increasing. In the period 1985-1991, utilities were responsible for 62 percent of the industry's additions to capacity, but that figure dropped to 48 percent in the period 1992-1998.

1. Introduction

The electric utility industry, once highly regulated, is becoming more competitive. In the past, retail customers purchased electricity from local utilities. Now, in some States, retail customers can shop around for an alternative electricity supplier with lower prices or better services. The transition to a competitive market for electricity has started but is not complete, nor is it occurring uniformly across the country. As of mid-1999, about 24 States are implementing retail competition, and more States are expected to follow.[1]

At the national level, the Energy Policy Act of 1992 (EPACT) and orders by the Federal Energy Regulatory Commission (FERC), the agency responsible for regulating interstate commerce of electricity, have promoted wholesale electricity competition. EPACT makes it easier for certain independent electricity suppliers to generate electric power and sell the power in wholesale electricity markets by exempting them from the constraints of the Public Utility Holding Company Act of 1935 (PUHCA).[2] These independent electric companies compete against traditional electric utilities for the sale of electric power in wholesale and retail electricity markets. FERC Order 888 further promoted wholesale electricity competition by providing open access to the bulk power transmission grid to all electricity suppliers including power marketers, electric utilities, and nonutilities (i.e., power generation companies that are not utilities and therefore do not have a franchised service territory or own transmission facilities). Prior to Order 888, electric utilities owning bulk power transmission lines could restrict competitors' ability to move power by restricting access to their transmission lines.

Now that the industry is becoming more competitive, electricity suppliers are developing strategies to enhance their ability to compete. More and more the strategy involves a corporate combination such as a merger, joint venture, or business alliance to strengthen a company's position in the industry, or a divestiture of certain assets to refocus a company's business line. Corporate combinations are not new to the electric power industry. Mergers between electric utilities, for example, have been employed many times to improve a company's performance. Over the past few years, however, the size and frequency of mergers among investor-owned electric utilities (IOUs) have increased dramatically.

This report presents data about corporate combinations involving IOUs in the United States, discusses corporate objectives for entering into such combinations, and assesses their cumulative effects on the structure of the industry. From the combinations that have taken place over the past few years, three trends have emerged: (1) an increase in the size of IOUs and the concentration of generation capacity within the IOU sector; (2) an expansion of IOUs, which once focused mainly on electricity production and delivery, into the natural gas industry (a trend that has been labeled "convergence" in the trade press and elsewhere); and (3) the move of many vertically integrated IOUs (i.e., utilities that own generation, transmission, and distribution assets) to exit the power generation business to become "wire" companies, enabling them to concentrate solely on operating their transmission and distribution systems.

Chapter 2 presents an overview of ownership in the electric power industry, comparing the ownership structure from 1992 to 1998. It compares and analyzes changes in the number of companies and in the relative shares of nameplate capacity, net generation, and additions to capacity by type of ownership. The year 1992 was selected because it was the year in which EPACT was passed by the U.S. Congress, and it represents, to a large extent, the beginning of the restructuring of the electric power industry.

Chapter 3 discusses mergers and acquisitions among electric utilities. It takes a quantitative look at the trend in consolidation of generation capacity caused by mergers and acquisitions, followed by a brief discussion of the primary reasons for electric utility mergers. Next, there is a discussion of specific developments in the

[1] The Energy Information Administration's Internet site displays the status of State electricity industry restructuring programs (http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html).

[2] Appendix A contains a discussion of the Public Utility Holding Company Act of 1935.

industry related to the merger trend: (1) pending mergers that will create large vertically integrated power companies and significantly advance the consolidation trend in the industry; (2) the creation of large regional energy delivery companies; and (3) first-of-a-kind mergers involving electric utilities, independent power producers, and foreign utilities. The final section of the chapter discusses regulatory review of electric utility mergers and the FERC's role in ensuring Nonutilitythat combined companies will not have excess market power.

Chapter 4 discusses mergers and acquisitions between electric utilities and natural gas companies—or "convergence mergers." A combined natural gas and electric distribution utility is not new, but recent mergers involving vertically integrated electric utilities and integrated natural gas companies have created energy companies that produce, transport, market, and sell both gas and electricity. The chapter includes a listing of convergence mergers and a discussion of the rationale behind some of the major ones.

Two different forms of corporate combinations—joint ventures and marketing alliances of electric utilities—are discussed in Chapter 5. Many utilities enter joint ventures or marketing alliances in order to share the costs of new ventures, reduce risks, or capitalize on the expertise of other companies. Joint ventures and alliances have been around for some time, but in today's environment they tend to be used more.

Over the past year or more, many IOUs have sold some or all of their power generation assets. This trend is new to the electric power industry, and it signifies fundamental changes in corporate ownership of power generation in the United States. Chapter 6 analyzes utility divestitures of generating assets, which are expected to continue as more States move to restructure the electricity industry in their jurisdictions.

Appendix A presents a discussion of the Public Utility Holding Company Act of 1935. Many industry observers believe that this Act unfairly constrains registered holding companies, is no longer relevant in today's industry, and, therefore, should be repealed. Proposals to repeal or modify the Act have been introduced into the current Congress and are summarized in the appendix.

Appendix B contains case studies describing the process of asset divestiture for three utilities. It discusses the reasons given by the utilities for divesting their assets, the auction process, and special issues that may affect the selling of power generation assets.

Appendices C and D are two detailed case studies of electric utility mergers. Significant cost savings are almost always used to justify mergers to the regulatory authorities responsible for approving them. The objective of the case studies was to determine, using public data, whether the mergers resulted in the savings originally estimated by the companies.

Appendix E contains definitions of various types of corporate combinations.

2. Organizational Components of the Electric Power Industry

This chapter examines the components that make up the infrastructure of the electric power industry. It explains their ownership characteristics, their current role in electricity supply, and how some roles have shifted since passage of the Energy Policy Act of 1992 (EPACT). EPACT, which provided a Federal mandate to open up the national electricity transmission system to wholesale suppliers, marked the beginning of competition in the electric power industry and was the impetus for significant structural changes. In 1996, the Federal Energy Regulatory Commission (FERC) issued its Order 888, which carried out the goal of EPACT.[3] From the 1970s until 1992, little change had occurred in the industry, either structurally or operationally, with the exception of the creation of nonutility qualifying facilities brought about by the Public Utility Regulatory Policies Act of 1978 (PURPA).[4] The data presented in this analysis are for 1998. In some cases, data for 1992 are compared with 1998 data to show trends.

Generation of electricity in the United States is performed by two types of companies—utilities and nonutilities. Table 1 presents their numbers and characteristics by ownership category. An electric utility is a private company or public agency engaged in the generation, transmission, and / or distribution of electric power that is given a monopoly franchise over a specific geographic area. In return for this franchise, the electric utility is regulated by State and Federal agencies. Utilities can be further classified into four subcategories based on ownership—investor-owned (IOU), Federally owned, other publicly owned, and cooperatively owned. Recently a fifth subcategory of electric utilities has emerged—the power marketers. They are classified as electric utilities because they buy and sell electricity. However, they do not own or operate generation, transmission, or distribution facilities, and therefore, their data (primarily electricity purchase and sales data) are not included in this chapter, except to give their characteristics in Table 1. Although relatively small in terms of volume of sales, the power marketers are a growing segment of the industry. Currently, about 400 power marketers have filed rate tariffs with FERC to sell electric power. Forty-nine power marketers reported retail sales and 111 reported wholesale sales during 1998.

In addition to power marketers, several other entities have come into existence as a result of the move to competition and can be added to the operational underpinnings of the electric power industry—namely, regional independent transmission system operators (ISOs), power exchanges (PXs), and futures contracts. Power marketers are the only one of the new entities that report to the Energy Information Administration (EIA) in its ongoing data collection program.[5]

Nonutilities are companies that generate power for their own use and / or for sale in wholesale markets.[6] Past EIA reports have subcategorized nonutilities (for example, as qualifying or nonqualifying facility cogenerators, small power producers, exempt wholesale generators, etc.[7]) based on their qualifications under certain Federal laws. However, as the industry furthers its transition to full retail competition in the generation portion of electricity

[3] FERC could not mandate an electric utility to open its transmission system for wholesale electric trade until EPACT amended the Federal Power Act.

[4] For further details on qualifying facilities and the Public Utility Regulatory Policies Act of 1978 and other laws that have had significant impacts on electric power supply, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE / EIA-0562(96) (Washington, DC, December 1996), Chapter 4.

[5] For details surrounding these recently emerged elements, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE / EIA-0562(96) (Washington, DC, December 1996), and *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE / EIA-0562(98) (Washington, DC, July 1998).

[6] Another term for a nonutility is an "independent power producer" (IPP). The two terms are used interchangeably throughout this report.

[7] For details on each of these nonutility subsections, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE / EIA-0562(96) (Washington, DC, December 1996), pp. 13-15.

Table 1. Major Characteristics of Electricity Providers by Type of Ownership, 1998

Ownership	Major Characteristics
Investor-Owned Utilities (IOUs) IOUs account for about three-quarters of all utility generation and capacity. There are 239 in the United States, and they operate in all States except Nebraska. They are also referred to as privately owned utilities.	• Earn a return for investors; either distribute their profits to stockholders as dividends or reinvest the profits • Are granted service monopolies in specified geographic areas • Have obligation to serve and to provide reliable electric power • Are regulated by State and Federal governments, which in turn approve rates that allow a fair rate of return on investment • Most are operating companies that provide basic services for generation, transmission, and distribution
Federally Owned Utilities There are 10 Federally owned utilities in the United States, and they operate in all areas except the Northeast, the upper Midwest, and Hawaii.	• Power not generated for profit • Publicly owned utilities, cooperatives, and other nonprofit entities are given preference in purchasing from them • Primarily producers and wholesalers • Producing agencies for some are the U.S. Army Corps of Engineers, the U.S. Bureau of Reclamation, and the International Water and Boundary Commission • Electricity generated by these agencies is marketed by Federal power marketing administrations in the U.S. Department of Energy • The Tennessee Valley Authority is the largest producer of electricity in this category and markets at both wholesale and retail levels
Other Publicly Owned Utilities Other publicly owned utilities include: Municipals Public Power Districts State Authorities Irrigation Districts Other State Organizations There are 2,009 in the United States.	• Are nonprofit State and local government agencies • Serve at cost; return excess funds to the consumers in the form of community contributions and reduced rates • Most municipals just distribute power, although some large ones produce and transmit electricity; they are financed from municipal treasuries and revenue bonds • Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California; voters in a public power district elect commissioners or directors to govern the district independent of any municipal government • Irrigation districts may have still other forms of organization (e.g., in the Salt River Project Agricultural Improvement and Power District in Arizona, votes for the Board of Directors are apportioned according to the size of landholdings) • State authorities, such as the New York Power Authority and the South Carolina Public Service Authority, are agents of their respective State governments
Cooperatively Owned Utilities There are 912 cooperatively owned utilities in the United States, and they operate in all States except Connecticut, Hawaii, Rhode Island, and the District of Columbia.	• Owned by members (rural farmers and communities) • Provide service mostly to members • Incorporated under State law and directed by an elected board of directors which, in turn, selects a manager • The Rural Utilities Service (formerly the Rural Electrification Administration) in the U.S. Department of Agriculture was established under the Rural Electrification Act of 1936 with the purpose of extending credit to co-ops to provide electric service to small rural communities (usually fewer than 1,500 consumers) and farms where it was relatively expensive to provide service
Nonutilities There are 1,934 nonutility power producers in the United States.	• Generate power for their own use and/or for sale in wholesale power markets • Can be subcategorized as qualifying facility (QF) cogenerators, non-QF cogenerators, QF small power producers, exempt wholesale generators, and/or non-QF other. • Also generally referred to as independent power producers
Power Marketers Approximately 400 have filed with FERC.	• Some are utility-affiliated while others are independent • Buy and sell electricity • Do not own or operate generation, transmission, or distribution facilities

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

supply, the distinctions between the nonutility subcategories are becoming less clear, and some may fade entirely within the next 10 years as a result of ongoing structural changes and the imminent repeal of the Federal mandates that created them. For purposes of this report, nonutility data are reported in the aggregate.

Utilities and nonutilities can also be broken down in a different manner, i.e., the number of companies that generate, transmit, and / or distribute electric power. It is interesting to note that only about 27 percent of the Nation's 3,170 utilities actually generate electric power. Many electric utilities (67 percent) are exclusively distribution utilities, purchasing wholesale power from others to distribute it, over their own distribution lines, to the ultimate consumer. These are primarily the utilities owned by State and local governments and cooperatives. Conversely, all nonutilities generate power but do not own or operate transmission or distribution systems (Table 2).

The relative contribution of utility and nonutility components to the supply of the Nation's electricity can be understood by looking at their shares of nameplate capacity,[8] net generation,[9] additions to capacity, and number of companies (Figure 1). The number of publicly owned utilities (i.e., those owned by State and local governments) far outweighs the number of IOUs (2,009 versus 239); however, IOUs are responsible for the lion's share of capacity (66 percent) and generation (68 percent). On the other hand, the nonutility share of capacity and generation has been relatively small, but that trend is changing. The change began with the passage of PURPA when nonutilities were promoted as energy-efficient, environment-friendly alternative sources of electricity. More recently, FERC Order 888 opened the bulk power transmission grid to suppliers other than utilities. In response, nonutilities have been expanding their roles in wholesale power supply and are taking advantage of the divestiture activities of utilities by purchasing their generation assets. As a result, the nonutility share of total industry capacity rose from 7 percent in 1992 to 12 percent in 1998.[10]

A yearly comparison of the above-mentioned four statistics (Figure 2) gives a clear picture of the significant shifts in ownership of electricity supply that have taken place in the relatively short period of time since passage of EPACT. A number of these shifts can be attributed to the strategic business plans companies are using to cope in a deregulated and competitive market. For instance, since 1992, the number of IOUs has decreased by nearly 8 percent and their nameplate capacity has decreased by 5 percent (Figure 3). The decrease in the number of IOUs is a result of recent mergers between IOUs. The decrease in generation capacity is evidence of divestiture of generation assets. On the other hand, the fact that IOU net generation has actually increased by 11 percent since 1992 can be attributed to such factors as higher demand for electricity or efficiency gains stemming from competition and mergers.

Although there was a drop in the number of nonutility companies in 1997, nonutilities grew by over 9 percent during the 7-year period examined. Also, with nonutilities expanding by buying IOU generation assets and constructing new generation units, the result was an increase in nonutility nameplate capacity (up 72 percent since 1992) and generation (up 42 percent since 1992). Nonutility additions to capacity have been increasing at an average annual rate of nearly 7 percent since 1992.

Historically, utilities have generally been vertically integrated companies that provided for generation, transmission, and / or distribution for all customers in a designated franchised service territory. Currently, the industry is in transition from a vertically integrated and regulated monopoly to a functionally unbundled industry with a competitive market for power generation. Market forces will replace State and Federal regulators in setting the price and terms of electricity supply and are expected to lead to lower rates for customers. In addition, the individual States are moving toward opening their retail markets to competition. The transition has begun to induce many far-reaching changes in the structure of the industry (and the institutions that govern it) especially through the corporate combinations that are the subject of this report. The following chapters address the objectives, characteristics, and cumulative effects of these corporate combinations—mergers and acquisitions, convergence mergers, joint ventures and marketing alliances, and divestitures of generation assets.

[8] EIA defines nameplate capacity as the maximum design production capacity specified by the manufacturer of a processing unit or the maximum amount of a product that can be produced running the manufacturing unit at full capacity.

[9] EIA defines net generation as gross generation minus plant use from all electric utility-owned plants.

[10] Energy Information Administration, *1998 Electric Power Annual, Volume I* (DOE / EIA-0348(98) / 1) (Washington, DC, April 1999), p. 1.

Table 2. Energy Supply Participants and Their Operations, 1998

Participants/Operations	Number of Companies	Percent of All Utilities
Vertically Integrated (Generate,[a] Transmit,[b] and Distribute[c])		
Utilities Only		
Investor Owned	140	4.4
Federal	3	0.1
Publicly Owned	132	4.2
Cooperatives	20	0.6
Total	295	9.3
Generate and Transmit Only		
Utilities Only		
Investor Owned	10	0.3
Federal	3	0.1
Publicly Owned	36	1.1
Cooperatives	40	1.3
Total	89	2.8
Transmit and Distribute Only		
Utilities Only		
Investor Owned	6	0.2
Federal	1	0.0
Publicly Owned	58	1.8
Cooperatives	74	2.3
Total	139	4.4
Generate and Distribute Only		
Utilities Only		
Investor Owned	25	0.8
Federal	2	0.1
Publicly Owned	403	12.7
Cooperatives	23	0.7
Total	453	14.3
Generate Only		
Utilities		
Investor Owned	11	0.3
Federal	0	--
Publicly Owned	12	0.4
Cooperatives	1	0.0
Total	24	0.8
Nonutilities	1,930	[d]100.0
Transmit Only		
Utilities Only		
Investor Owned	7	0.2
Federal	0	--
Publicly Owned	8	0.3
Cooperatives	19	0.6
Total	34	1.1

See notes at end of table.

Table 2. Energy Supply Participants and Their Operations, 1998 (Continued)

Participants/Operations	Number of Companies	Percent of All Utilities
Distribute Only		
Utilities Only		
Investor Owned	34	1.1
Federal	1	0.0
Publicly Owned	1,358	42.8
Cooperatives	735	23.2
Total	2,128	67.1
Other[e]		
Utilities Only		
Investor Owned	6	0.2
Publicly Owned	2	0.1
Total	8	0.2
Power Marketers[f]	[g]400	–

[a]An electricity generator is a facility that converts mechanical energy into electrical energy.

[b]An electricity transmitter moves or transfers electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

[c]An electricity distributor delivers electric energy to an end user.

[d]This figure represents the percentage of nonutilities rather than utilities.

[e]"Other" includes maintenance service companies for parent utilities that perform such functions as guard services, equipment maintenance, etc. Also, one of the publicly owned utilities in this category acts as an agent to buy and schedule power for the parent utility.

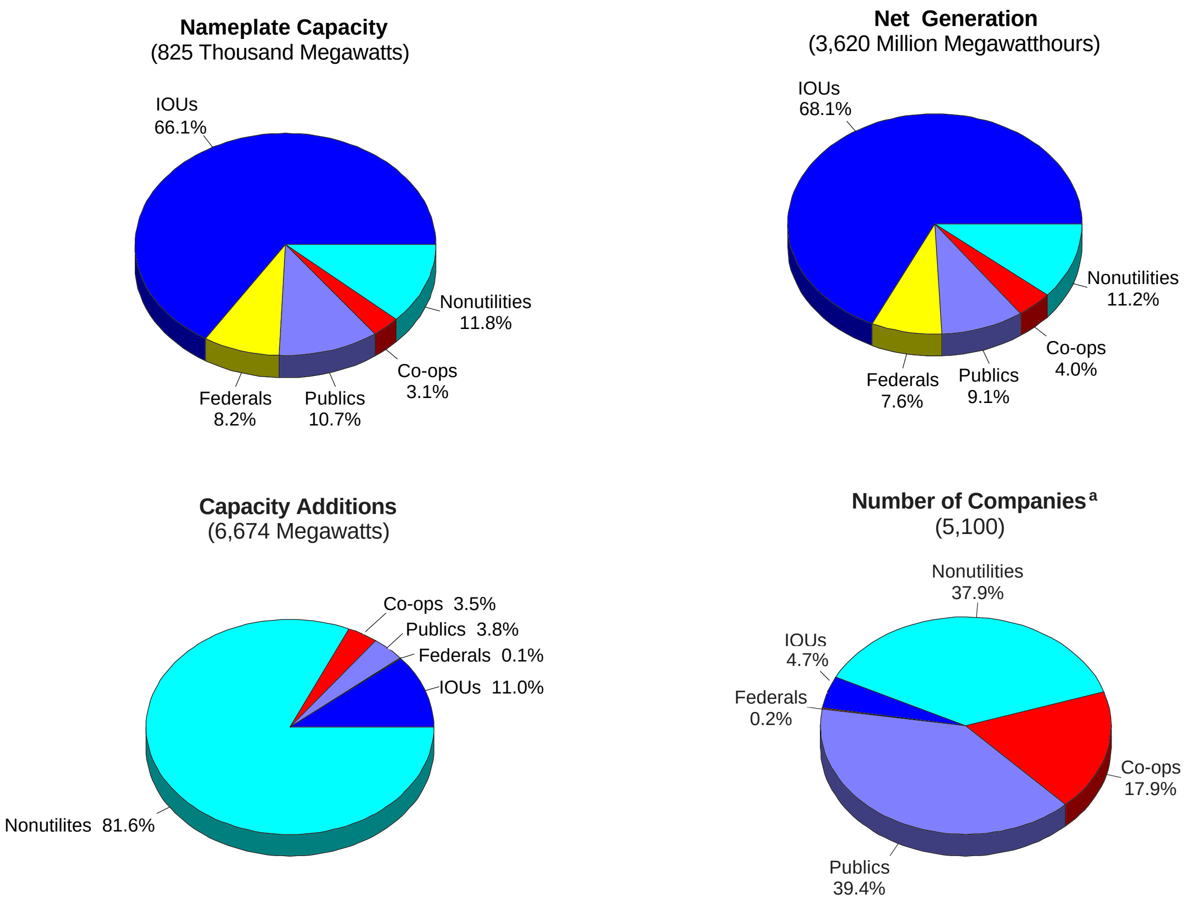
[f]An electricity power marketer buys and sells electricity but does not own or operate generation, transmission, or distribution facilities.

[g]Currently, about 400 power marketers have filed rate tariffs with FERC; 111 reported wholesale sales and 49 reported retail sales during 1998.

-- = Not applicable.

Sources: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report, 1998," and EIA-860B, "Annual Electric Generator Report - Nonutility, 1998."

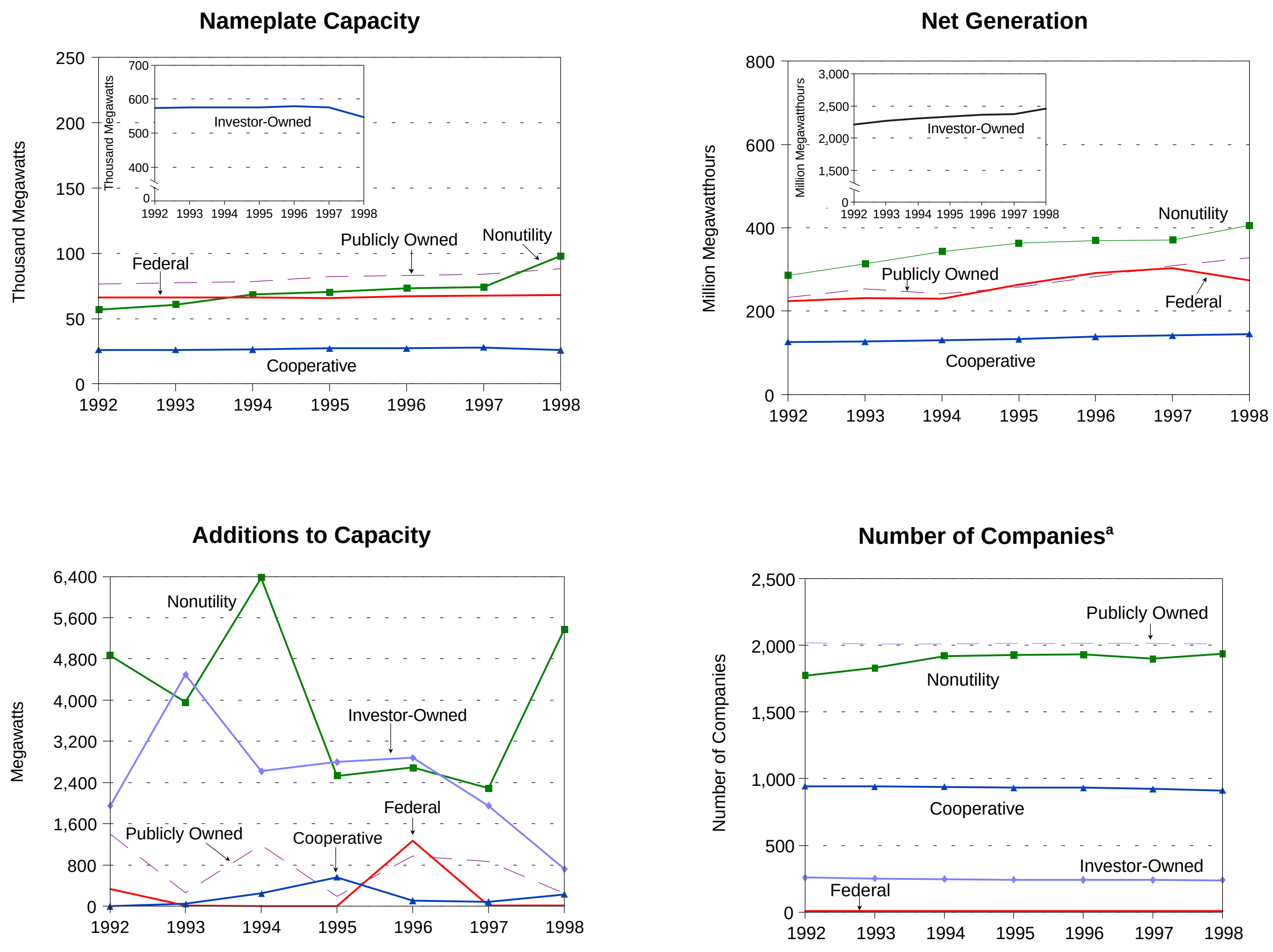
Figure 1. Share of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, “Monthly Power Plant Report, December 1998;” EIA-860A, “Annual Electric Generator Report - Utility, 1998;” EIA-861, “Annual Electric Utility Report, 1998;” and EIA-860B, “Annual Electric Generator Report - Nonutility, 1998.”

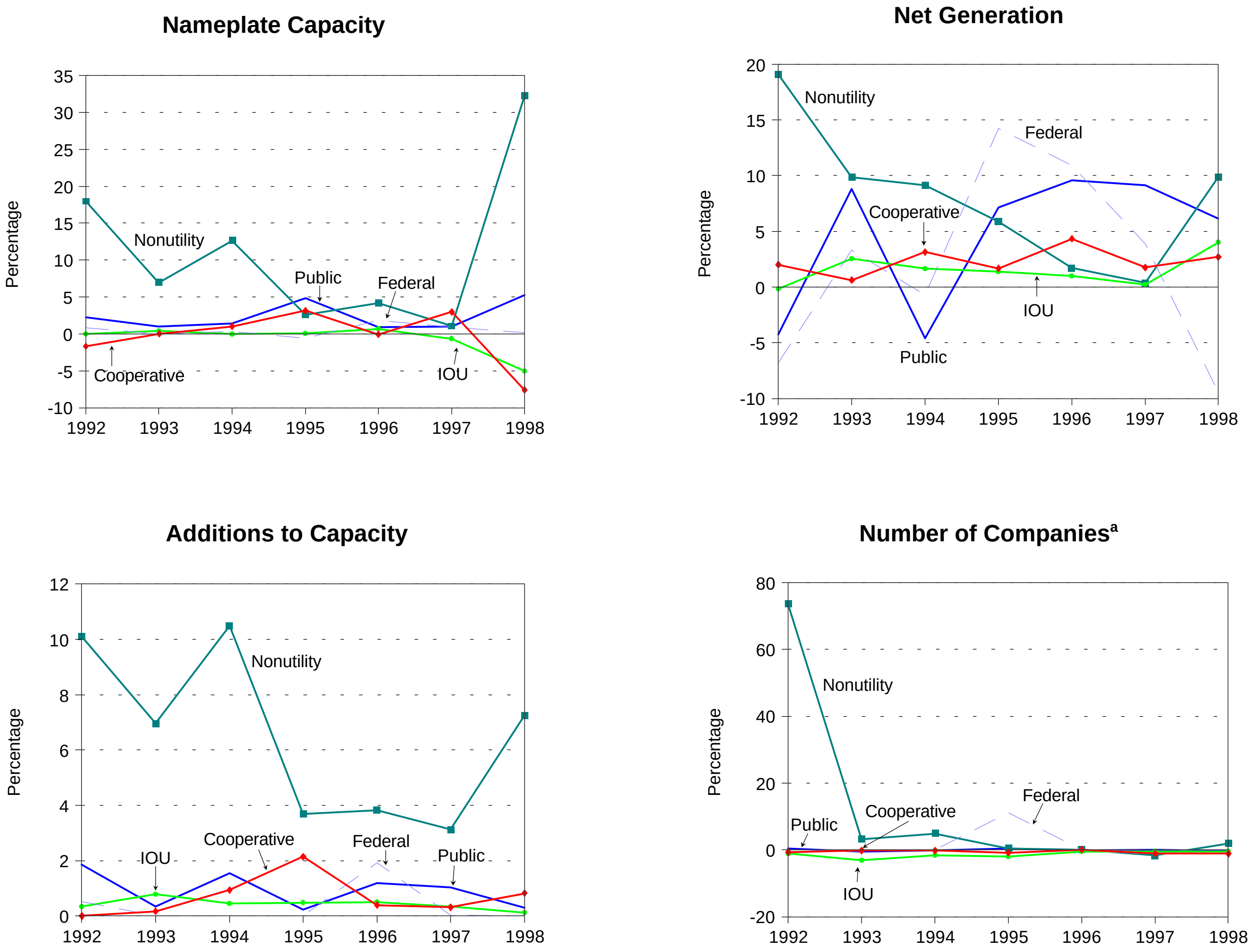
Figure 2. Total Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Units by Ownership Category, 1992-1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report, January 1992 through December 1998;" Form EIA-860, "Annual Electric Generator Report, 1992 through 1997;" EIA-860A, "Annual Electric Generator Report - Utility, 1998;" EIA-861, "Annual Electric Utility Report, 1992 through 1998;" EIA 867, "Annual Nonutility Power Producer Report, 1992 through 1997;" and EIA-860B, "Annual Electric Generator Report - Nonutility, 1998."

Figure 3. Annual Growth Rate of Utility and Nonutility Nameplate Capacity, Net Generation, Additions to Capacity, and Number of Companies, 1992-1998



[a] Data for power marketers are not included.

Sources: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report, January 1992 through December 1998;" Form EIA-860, "Annual Electric Generator Report, 1992 through 1997;" EIA-860A, "Annual Electric Generator Report - Utility, 1998;" EIA-861, "Annual Electric Utility Report, 1992 through 1998;" EIA 867, "Annual Nonutility Power Producer Report, 1992 through 1997;" and EIA-860B, "Annual Electric Generator Report - Nonutility, 1998."

3. Mergers and Acquisitions of Investor-Owned Electric Utilities

Mergers and acquisitions are occurring throughout the U.S. economy, and the electric power industry is no exception.[11] Since 1992, 26 mergers or acquisitions have been completed between investor-owned utilities (IOUs) or between IOUs and independent power producers (IPPs). Sixteen mergers have been announced and are now pending stockholder or Federal and State government approval (Table 3).[12] The size of IOU mergers, in terms of value of assets, is also getting larger. Between 1992 and 1998, only four mergers were completed in which the combined assets of the companies in each merger were greater than $10 billion. More recently, 10 mergers either completed in 1999 or pending completion each have combined assets greater than $10 billion.

The current wave of mergers and acquisitions is not the first wave in the electric power industry. From 1917 through 1930, mergers of electric utilities were more common than at any other time in the history of the industry. Mergers occurred at a rate of more than 200 per year, peaking at over 300 per year in the mid-1920s.[13] Most of the mergers in the 1920s combined small operating companies into large holding companies. These holding companies acquired numerous and widely scattered utility and nonutility properties throughout the United States, and they became a dominant force in the industry by permitting concentration of control of many electric utilities in the hands of a few. This era can clearly be considered the first wave of mergers in the history of the industry, but it came to an end in 1935.

In the early 1930s many of the holding companies collapsed financially. The Federal Trade Commission (FTC) investigated the situation and uncovered a host of financial abuses, leading to passage of the Public Utility Holding Company Act of 1935 (PUHCA). (See Appendix A for a discussion of the Act.) Among other things, the Act resulted in the reorganization and divestiture of assets of many of the holding companies, and the requirement that the remaining holding companies be limited to a single integrated electricity system. Between 1935 and 1950, more than 750 utilities were spun off from the holding companies, and by the early 1950s compliance with the requirements of PUHCA were nearing completion.

Following the breakup of the large holding companies, mergers continued, but at a much lower rate. From 1936 through 1975 there were 517 mergers, occurring at an annual rate of less than 15 a year. From 1976 through 1998, 76 mergers have taken place, about 3 per year on average. The distinguishing difference between the heyday of mergers occurring early in the industry and now, is the relative size of the mergers. It is no longer smaller companies being acquired by large companies, but in many cases it is large companies merging with other large companies. "Mega-mergers" is the term used to describe such large mergers.

Some financial analysts say that good economic conditions and relatively high stock values are responsible for the current wave of electric utility mergers. High stock prices allow companies to take an inexpensive source of capital (common stock in this case) and buy other companies in a stock-for-stock transaction. However, the current wave of utility mergers is probably driven more by increasing competition in the electric power industry, although financial factors play a part. Mergers of IOUs can be classified broadly into two categories, each category representing a fundamentally different reason for merging. The first category includes mergers between IOUs and mergers between IOUs and

[11] For this report no attempt was made to classify a transaction as a merger or acquisition, although there is a difference in terms of how the financial accounting of the transaction is recorded. Throughout the report, the transactions are collectively referred to as mergers and acquisitions or mergers.

[12] This report covers IOU acquisitions of other electric utilities, privately owned IPPs, and companies involved in the natural gas industry. It does not cover IOU acquisitions of foreign companies or non-energy-related companies.

[13] National Regulatory Research Institute, Electric Utility Mergers and Regulatory Policy, Occasional paper #16, NRRI 92-12 (June, 1992).

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**Allegheny Energy, Inc.** (a registered holding company for Monongahela Power Co.,The Potomac Edison Co., West Penn Power, Allegheny Generating Co., and Ohio Valley Electric Corp.)	**DQE, Inc**. (a holding company for Duquesne Light Co.)	**Allegheny Energy, Inc**. (DQE will be a wholly-owned subsidiary of Allegheny Energy, Inc.)	PA, WV, OH, MD	Allegheny: $6.7 DQE: $5.2 Total: $11.9	DQE informed Allegheny that it has terminated the merger plan. Allegheny took legal action in Federal Court to compel DQE to honor its obligation. Case is pending.
Pending	**Western Resources** (a holding company for Kansas Gas and Electric Co.; partial owner of Wolf Creek Nuclear Operating Co.)	**Kansas City Power & Light** (an operating utility)	**Westar Energy** (proposed name of new holding company)	KS, MO	Western: $8.0 Kansas City P&L: $3.0 Total: $11.0	Under State regulatory review.
Pending	**American Electric Power Co., Inc.** (a registered holding company for AEP Generating Co., Appalachian Power Co., Columbus Southern Power, Indiana Michigan Power Co., Kentucky Power Co., Kingsport Power Co., Ohio Power Co., and Wheeling Power Co.)	**Central and South West Corp.** (a registered holding company for Central Power and Light Co., Public Service Co. of Oklahoma, Southwestern Electric Power Co., and West Texas Utilities Co.)	**American Electric Power Co.** (Central and South West will be a wholly-owned subsidiary)	VA, WV OH, IN MI, KY TN, TX OK, LA AR	AEP: $19.5 CSW: $13.7 Total: $33.2	On July 23, 1999, the Federal Energy Regulatory Commision (FERC) filed an order accelerating the schedule for review of this merger. The FERC's goal is to act on the merger in February or March 2000.
Pending	**Nevada Power** (an operating utility)	**Sierra Pacific Resources** (a holding company for Sierra Pacific Power Co.)	**Sierra Pacific Resources** (Nevada Power will be a wholly-owned subsidiary)	NV, CA	Nevada Power: $2.6 Sierra Pacific: $2.0 Total: $4.6	Received FERC and Department of Justice (DOJ) approval. Completion of merger expected in next few months.
Pending	**Consolidated Edison, Inc.** (a holding company for Consolidated Edison Co. of New York, Inc., and Orange and Rockland Utilities)	**Northeast Utilities** (a holding company for Connecticut Light & Power, Public Service Co. of New Hampshire, and Western Massachusetts Electric Co.)	**Consolidated Edison, Inc.** (Northeast Utilities will be a subsidiary)	NY, CT, MA, NH	Consolidated Edison: $14.4 Northeast: $10.4 Total: $24.8	Merger was announced October 13, 1999.
Pending	**AES Corporation** (an independent power producer)	**CILCORP** (a holding company for Central Illinois Light Co.)	**AES** (CILCORP will be a wholly-owned subsidiary)	IL	AES: $10.0 CILCORP: $1.3 Total: $11.3	Under SEC review; has completed all other reviews.
Pending	**BCE Energy** (a holding company for Boston Edison)	**Commonwealth Energy** (a holding company for Cambridge Electric Light Co., Canal Electric Co., and Commonwealth Electric Co.)	**NSTAR** (a new holding company; Boston Edison and Commonwealth Energy will be subsidiaries)	MA	BCE: $3.2 Commonwealth: $1.5 Total: $4.7	Under regulatory review.

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**Scottish Power PLC** (a foreign company)	**PacifiCorp** (an operating utility)	Unknown (a new holding company; PacifiCorp will be a subsidiary)	UT, OR, WY, WA, ID, MT, CA	Not available because Scottish Power is a foreign company.	Pending shareholder and regulatory approval; they hope to complete merger by late 1999.
Pending	**National Grid Group PLC** (a foreign company)	**New England Electric Systems (NEES)** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	**National Grid Group** (NEES will be a wholly-owned subsidiary)	VT, NH MA	Not available because National Grid Group is a foreign company.	Pending regulatory approval.
Pending	**Carolina Power & Light Co.** (an operating utility)	**Florida Progress Corp**. (a holding company for Florida Power Corp.)	Unknown	FL, NC, SC	CP&L: $8.3 Florida: $6.2 Total: $14.5	This merger was announced on August 23, 1999.
Pending	**New England Electric System** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragansett Electric Co., and New England Power Co.)	**Eastern Utility Associates** (a registered holding company for Blackstone Valley Electric Co., Newport Electric Corp., Eastern Edison Co., EUA, and Ocean State Corp.)	**New England Electric System** (EUA will be a wholly-owned subsidiary)	MA, RI VT, NH	NEES: $5.3 EUA: $1.3 Total: $6.6	EUA shareholders approved merger; pending regulatory review; expected to be completed in early 2000.
Pending	**UtiliCorp United** (a holding company)	**St. Joseph Light & Power** (an operating utility)	**Utilicorp** (St. Joseph will keep its name and become a wholly-owned subsidiary)	MO, KS CO, WV CO, KA	Utilicorp: $6.0 St. Joseph: $0.3 Total: $6.3	Under regulatory review.
Pending	**New Century Energies** (a registered holding company for Public Service Co. of Colorado, South-western Public Service Co., and Cheyenne Light, Fuel, & Power)	**Northern States Power** (a holding company)	**Xcel Energy** (unknown if New Centuries and Northern States Power operate as subsidiaries)	NM, OK TX, WY AR, MI MN, SD ND, WI	New Century: $7.7 NSP: $7.4 Total: $15.1	Under regulatory review.
Pending	**UtiliCorp United** (a holding company)	**Empire District Electric Co.** (an operating utility)	Unknown	MO, CO KA, WV OK, AR	Utilicorp: $6.3 Empire District: $0.7 Total: $7.0	Under regulatory review.

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Pending	**Energy East** (a holding company for New York Electric & Gas)	**CMP Group** (a holding company for Central Maine Power)	**Energy East** (CMP Group will be a wholly-owned subsidiary)	MA, MI NY, NH	Energy East: $4.9 CMP Group: $2.3 Total: $7.2	This merger was announced on June 15, 1999.
Pending	**Unicom Corporation** (a holding company for Commonwealth Edison)	**PECO Energy Co.** (a registered holding company for Susquehanna Power Co.)	A new holding company, to be named later, will be created.	IL, PA	Unicom: $30.2 Peco: $12.0 Total: $42.2	This merger was announced September 23, 1999.
Completed in 1999 (year-to-date)	**CalEnergy Co., Inc**. (an independent power producer)	**MidAmerican Energy Holding Co.** (a holding company for MidAmerican Energy Co.)	**MidAmerican Energy Holding** (CalEnergy will be a subsidiary)	KS	CalEnergy: $7.5 MidAmerican: $4.3 Total: $11.8	Completed.
	Consolidated Edison, Inc. (a holding company for Consolidated Edison Co. of New York, Inc.)	**Orange and Rockland Utilities** (an operating utility)	**Consolidated Edison, Inc**. (Orange and Rockland will be a wholly-owned subsidiary)	NY	ConEd: $14.4 O&R: $1.3 Total: $15.7	Completed.
Completed in 1998	**Delmarva Power & Light Co.** (an operating utility)	**Altantic Energy** (a holding company for Atlantic City Electric Co.)	**Conectiv** (a new registered holding company)	MD, DE VA, NJ	Delmarva Power: $3.0 Atlantic: $2.7 Total: $5.7	Completed.
	LG&E Energy (a holding company for Louisville Gas & Electric Co.)	**KU Energy** (a holding company for Kentucky Utilities)	**LG&E Energy** (KU Energy will be dissolved)	KY, VA TN	LG&E: $3.0 KU Energy: $1.7 Total: $4.7	Completed.
	WPL Holding, Inc. (a holding company for Wisconsin Power & Light)	**IES Industries** (a holding company for IES Utilities and Interstate Power, an operating utility)	**Alliant Energy** (a new holding company)	WI, IA MN, IL	WPL Holding: $1.9 IES: $2.5 Interstate: $0.6 Total: $5.0	Completed.
	Wisconsin Energy (a holding company for Wisconsin Electric Power Co.)	**ESELCO** (a holding company for Edison Sault Electric Co.)	**Wisconsin Energy Company** (ESELCO will be a wholly-owned subsidiary)	WI, MI	Wisconsin: $5.0 ESELCO: $0.1 Total: $5.1	Completed.
	WPS Resources (a holding company for Wisconsin Public Service Corp., Wisconsin River Power Co.)	**Upper Peninsula Energy** (a holding company for Upper Peninsula Power Co.)	**WPS Resources** (Upper Peninsula Energy will cease to exist)	WI, MI	WPS: $1.1 Upper Peninsula: $0.1 Total: $1.2	Completed.

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1997	**Ohio Edison Co.** (an operating utility; Ohio Edison also owns Pennsylvania Power Co.)	**Centerior Energy** (a holding company for Cleveland Electric Illuminating Co. and Toledo Edison Co.)	**FirstEnergy** (a new registered holding company)	OH	Ohio Edison: $8.9 Centerior: $10.2 Total: $19.1	Completed.
	Public Service Co. of Colorado (an operating utility and a holding company for Cheyenne Light, Fuel, and Power)	**Southwestern Public Service Co.** (an operating utility)	**New Century Energies** (a new registered holding company)	CO, TX NM, OK KS	PS Co. of CO: $4.6 Southwestern: $2.0 Total: $6.6	Completed.
	Union Electric Co. (an operating utility)	**CIPSCO** (a holding company for Central Illinois Public Service Co.)	**Ameren** (a new registered holding company)	MO, IL	Union: $6.8 CIPSCO: $1.8 Total: $8.6	Completed.
	Pacific Gas & Electric Corp. (a holding company for Pacific Gas & Electric)	**U.S. Generating Co. (USGen)** (an independent power producer)	**Pacific Gas & Electric Corp.** (USGen will be an unregulated affiliate of PG&E)	USGen has plants in numerous States	USGen: $5.0	PG&E acquired 50 percent in USGen. At the time, USGen had ownership in 17 electric generating facilities operating in the United States.
Completed in 1996	**New England Electric Systems** (a registered holding company for Granite State Electric Co., Massachusetts Electric Co., Narragan-sett Electric Co., and New England Power Co.)	**Nantucket Electric** (a small electric distribution company)	**New England Electric System** (Nantucket Electric is a subsidiary)	VT, NH MA	NEES: $5.1 Nantucket: $0.1 Total: $5.2	Completed.
Completed in 1995	**City of Groton, CT**	**Bozrah Light and Power**	Unknown	CT	Unknown	Completed.
	Delmarva Power and Light	**Conowingo Power Co.**	**Delmarva Power and Light**	DE,MD, VA	Delmarva Power: $2.9 Conowingo: $0.1 Total: $3.0	Completed.
	Midwest Resources (a holding company for Midwest Power Systems)	**Iowa-Illinois Gas and Electric** (an operating utility)	**MidAmerican Energy** (a holding company and operating utility)	IA, SD, IL	Midwest: $2.6 Iowa: $1.9 Total: $4.5	Completed.
Completed in 1994	**PSI Resources** (an operating utility)	**Cincinnati Gas & Electric** (an operating utility)	**CINergy** (PSI Resources and Cincinnati are wholly-owned subsidiaries)	IN,OH, KY	PSI Resources: $2.9 Cincinnati: $5.2 Total: $8.1	Completed.

Table 3. Mergers and Acquisitions Between Investor-Owned Electric Utilities or Between Investor-Owned Electric Utilities and Independent Power Producers, 1992 Through September 1999 (continued)

Merger Status	Company 1	Company 2	Name of Surviving Company or Name of New Company	States Served	Combined Assets (Year-of-Merger Dollars in Billions)	Comments/Status
Completed in 1993	**Citizens Utilities Co.** (an operating utility)	**Franklin Electric** (an operating utility)	**Citizens Utilities** (Franklin Electric ceased to exist)	AZ,HI, VT	Citizens: $2.6 Franklin: $0.8 Total: $3.4	Completed.
	IES Utilities Inc. (a holding company)	**Iowa Electric Light & Power and Iowa Southern Utilities**	**IES Industries** (IES Utilities, Iowa Electric, and Iowa Southern are subsidiaries)	IA	Total: $1.8	Completed.
	Texas Utilities (a holding company)	**Southwestern Electric Service Co.** (an operating utility)	**Texas Utilities** (Southwestern Electric is a subsidiary)	TX	Total: $20.9	Completed.
	Entergy Corp. (a holding company)	**Gulf States Utilities** (a holding company)	**Entergy Corp.** (Gulf States is a wholly-owned subsidiary)	AR,TN, LA, TX, MS, NY	Entergy: $14.2 Gulf States: $7.2 Total: $21.4	Completed.
Completed in 1992	**Connecticut Light & Power**	**Fletcher Electric Light Co.**	**Connecticut Light and Power**	CT	Total: $6.2	Completed.
	Iowa Public Service Co.	**Iowa Power Co.**	**Midwest Power**	IA, SD	Total: $2.6	Completed.
	Kansas Power & Light	**Kansas Gas & Electric**	**Western Resources**	KS	Total: $5.2	Completed.
	Indiana Michigan Power Co.	**Michigan Power Co.**	**Indiana Michigan Power Co.**	IN, MI	Total: $4.3	Completed.
	Unitil Corp.	**Fitchburg Gas & Electric**	**Unitil Corp.**	NH	Total: $0.2	Completed.
	Northeast Utilities	**Public Service of New Hampshire**	**Northeast Utilities**	NH, CT, MA	Total: $10.6	Completed.

Notes: U.S. investor-owned electric utility acquisitions of foreign companies are not included in this table.

Sources: Mergers and acquisitions were identified from trade journals, newspapers, and electric utility press releases found on their websites. Values for company assets were obtained from the Securities and Exchange Commission, 10-K filings.

IPPs. These mergers are motivated by the desire to increase power generation capacity and / or transmission and distribution capacity and in general become a larger electric utility. Most utility executives take the position that to compete successfully in today's electricity industry, a company must be relatively large.

The second category includes mergers between electric utilities and natural gas companies. These mergers are motivated by the desire to become a regional or national energy company that produces, transports, and / or sells both electricity and natural gas. Mergers of this type are called "convergence mergers" because they represent the increasing number of companies that own both electricity and natural gas assets and are actively engaged in both industries. Convergence mergers are discussed in Chapter 4.

Investor-Owned Electric Utilities Consolidating Generation Assets Through Mergers and Acquisitions

Mergers and acquisitions among IOUs over the past few years have resulted in fewer electric utilities owning generation capacity. In 1992, 172 IOUs owned generation capacity in the United States. By 1998 that number had decreased to 161 (Table 4).[14] Assuming that all mergers pending as of September 1999 will be approved and completed by 2000, the number of operating IOUs owning generation capacity will decrease to 143. Power plant divestitures, discussed in detail in Chapter 6, have also reduced the total number of IOUs owning generation capacity.

The majority of electric utilities are wholly-owned subsidiaries of public utility holding companies.[15] The

Table 4. Comparison of the Number of Investor-Owned Electric Utilities Owning Generation Capacity, 1992, 1998, and 2000

Company Category	1992			1998			2000 (Estimated)		
	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)	Number[a] of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)	Number of Operating Utilities	Number of Holding Companies	Generation Capacity (Percent and Thousand Megawatts)
Utility that Is a Subsidiary to a Holding Company.	113	70	(78%) 422.1	125	68	(83%) 441.0	114	53	(89%) 396.3
Independent Utility . . .	59	--	(22%) 120.3	36	--	(17%) 87.3	29	--	(11%) 49.0
Total	**172**	**70**	**(100%) 542.4**	**161**	**68**	**(100%) 528.3**	**143**	**53**	**(100%) 445.3**

[a]The number of utilities reported here does not match the number of utilities reported in Chapter 2 for the following reasons: (1) these data include IOUs that own power generation capacity, whereas the data reported in Chapter 2 include IOUs that operate power plants; (2) some utilities operate transmission and distribution systems only and are not included here; and (3) these data exclude Alaska and Hawaii.

Notes: • The 2000 data include the effects of pending mergers on consolidation of ownership. It is assumed that all pending mergers that were announced by September 30, 1999 will be completed by 2000. • Also, the 2000 data include the effects of generation asset divestitures on consolidation of ownership. It is assumed that all divestitures where a buyer has been announced as of September 30, 1999 will be completed by 2000. • Holding companies were identified from the following documents: U.S. Securities and Exchange Commission Financial and Corporate Reports, "Holding Companies Registered Under the Public Utility Holding Company Act of 1935 as of October 1, 1995, as of December 1, 1996, and as of June 1, 1998," and "Holding Companies Exempt from the Public Utility Holding Company Act of 1935 Under Section 3(a) (1) and 3(a) (2) Pursuant to Rule 2 Filings or By Order as of August 1, 1995 and as of November 1, 1997."

Sources: Energy Information Administration, Forms EIA-860, "Annual Electric Generator Report, 1992;" EIA-860A, "Annual Electric Generator Report - Utility, 1998;" and EIA-861, "Annual Electric Utility Report, 1992 and 1998."

[14] Because these figures include IOUs that own power generation capacity only, they do not match data in Chapter 2, which discusses the number of utilities that operate power plants. Some utilities own power generation capacity but do not operate a power plant, and some utilities operate power plants but do not own them.

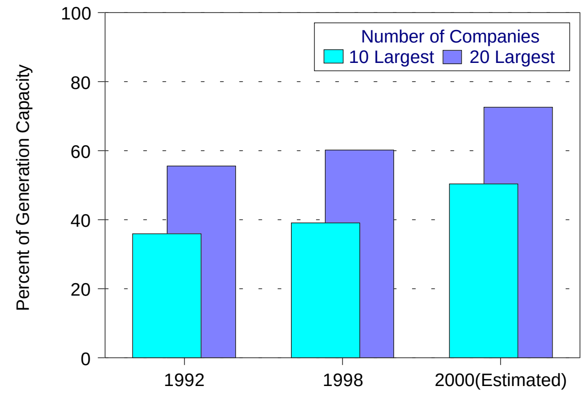
[15] In some cases a holding company will also be a subsidiary of another holding company. The number of holding companies cited in this report refers to the highest level holding company.

affect of mergers on consolidation of the industry is more evident when ownership capacity is aggregated by holding company. In 1992, there were 70 holding companies owning 78 percent of the IOU-held generation capacity (Table 4). By 1998 the number of holding companies decreased to 68, but yet the percent of total IOU-owned capacity increased to 83 percent, primarily because of mergers and acquisitions between IOUs. Assuming that all mergers pending as of September 1999 are completed by 2000, the number of holding companies will decrease to 53, and the generation capacity they own will increase to about 89 percent of the total IOU-owned capacity. The number of holding companies will decrease because most of the pending mergers are between holding companies, which indicates that relatively large companies are becoming even larger.

Although many IOUs that own power generation capacity have merged or have announced plans to merge, the majority of them have not. Of the 104 IOUs (either electric utility holding companies or independent electric utilities) that owned generation capacity in 1998 (see Table 4), 60 (58 percent) have not been involved in a merger since 1992 and have not announced plans to merge. This suggests that even though the merger trend is strong, most IOUs believe consolidation is not necessary to remain competitive in the industry in spite of the fact that those companies choosing to merge are acquiring a larger share of the industry's assets.

The absolute number of companies provides insight into consolidation trends, but concentration of generation capacity ownership is perhaps more indicative of consolidation.[16] As a measure of consolidation of the industry, concentration indicates the extent to which total capacity ownership is dispersed among companies. The data suggest that generation capacity owned by IOUs has been concentrated in the hands of a few companies, and that mergers and acquisitions are increasing the concentration of ownership. In 1992, the 10 largest utilities, ranked according to generation capacity, owned 33 percent of all IOU generation capacity; by 1998 their share had increased to 39 percent, primarily as a result of mergers (Figure 4). Again, assuming that all pending mergers will be completed by 2000, the 10 largest companies' share will increase to about 51 percent. Evidence of consolidation among the 20 largest companies is even more compelling: in 1998 the 20 largest companies owned 60 percent of total IOU generation capacity; by 2000 their share is expected to increase to approximately 73 percent, assuming that all pending mergers are completed.

Figure 4. Concentration of Ownership of Investor-Owned Utility Generating Capacity, 1992, 1998, and 2000



Notes: •The 10 largest companies are public utility holding companies that own one or more operating electric utilities. • The 2000 data assume that all pending mergers as of September 1999 will be completed by year-end 2000. •Capacity owned by subsidiaries of IOUs was not counted when computing the rankings.

Sources: Energy Information Administration, Form EIA-860, "Annual Electric Generation Report,1992;" Form EIA-860A, "Annual Electric Generator Report - Utility,1998;" and EIA-861, "Annual Electric Utility Report (1992 and 1998)."

The conclusion suggested by the data is that power generation capacity owned by IOUs is becoming concentrated in companies that are becoming larger through mergers and acquisitions. However, because of power plant divestitures, IOUs, as a whole, will own less of the Nation's power generation capacity in the future. Mergers and acquisitions also result in consolidation of bulk power transmission systems and distribution systems. This trend is not quantified in the report, but examples of it are discussed below.

Ranking of Largest Investor-Owned Electric Utilities

The 10 largest owners of power generation capacity in the United States are public utility holding companies

[16] Concentration of generation capacity does not imply market power or the ability to charge higher prices. Market power and other issues concerning the effects of a merger on competition are reviewed by the Federal Energy Regulatory Commission.

(Table 5).[17] Presently, Southern Company is the largest, with six electric utility subsidiaries located in the southeastern United States. Southern Company not only has six electric utility subsidiaries, it also owns Southern Energy, an IPP active in the purchase and construction of power plants throughout the United States. As a side note, many public utility holding companies own IPP subsidiary companies that generate and sell power in wholesale markets. The number of IPPs and their share of total generation capacity in the United States are expected to increase.

American Electric Power Company (AEP), the second largest company in 1992, had dropped to third by 1998 because of a merger between Entergy Corporation and Gulf States Utilities. AEP, with eight operating electric utility subsidiaries, is attempting to merge with Central & Southwest Corporation, a large utility holding company with four operating electric utilities. If that merger is approved, the combined company will become the largest IOU holding company in the United States, in terms of power generation capacity.

Two companies, SCE Corporation and Pacific Gas & Electric Corporation, have divested or are in the process of divesting a large portion of their power generation assets. As a result, they have dropped from the list of the 10 largest companies in the 2000 ranking based on ownership of generation capacity. Interestingly, Unicom is also divesting its fossil-fuel generation capacity, representing almost one-half of its total capacity, but plans to hold onto its nuclear power plants. In September 1999 Unicom and Peco Energy announced merger plans. When completed the new company will be the fifth largest IOU in the Nation, and one of the largest producers of electricity using nuclear power in the United States.

Some of these top electric power companies have invested in other energy-related industries, with large investments in natural gas production, pipelines, storage, or gas distribution. Duke Energy Corporation, for example, has embarked on an aggressive growth plan to become a leading energy company and is now one of the largest combined electric power and natural gas companies in the United States.

Table 5. Ranking of the 10 Largest Investor-Owned Companies by Ownership of Generation Capacity, 1992, 1998, and 2000

Company	1992 Ranking	1998 Ranking	2000 (Estimated) Ranking
Southern Company	1	1	2
American Electric Power Company	2	3	[a]1
Unicom (formerly Commonwealth Edison)	3	5	Not in 10 largest
TXU (formerly Texas Utilities Company)	4	4	4
Duke Energy Corporation	5	7	8
Entergy Corporation	6	2	3
FPL Group, Inc. (Florida Power & Light)	7	6	7
SCE Corp. (Southern California Edison)	8	Not in 10 largest	Not in 10 largest
PG&E Corporation (Pacific Gas & Electric)	9	Not in 10 largest	Not in 10 largest
Reliant Energy (formerly Houston Industries)	10	9	10
New Century Energies	Did not exist	Not in 10 largest	[b]8
First Energy	Did not exist	8	10
Carolina Power & Light/Florida Progress[c]	Did not exist	Did not exist	6
Dominion Resources, Inc.	Not in 10 largest	10	Not in 10 largest
Unicom/Peco	Did not exist	Did not exist	5
Xcel Energy (New Century Energies/Northern States Power)[d]	Did not exist	Did not exist	9

[a] Assumes merger with Central & Southwest Corp. will be completed by 2000.
[b] Assumes merger with Nothern States Power will be completed by 2000.
[c] Assumes merger will be completed by 2000.
[d] Assumes merger between New Century Energies and Northern States Power will be completed by 2000.
Notes: •The 10 largest companies are public utility holding companies that own one or more operating electric utilities.
•Capacity owned by IPP subsidiaries of these companies was not counted in computing the rankings.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

[17] Other criteria for ranking these companies (i.e., total assets) would produce significantly different results; some of these companies would drop out of the 10-largest list.

Reasons for Mergers and Acquisitions Among Electric Utilities

"Electric utilities must be relatively large to be competitive in the electricity industry" is a position argued by most, if not all, utility executives who have directed their companies through mergers. This belief by utility executives underlies many of the mergers and acquisitions among IOUs. Why does size matter? Increased size enables a company to achieve economies of scale. By combining resources and eliminating redundant or overlapping activities, larger companies can benefit from increased efficiencies in procurement, production, marketing, administration, and other functional areas that smaller companies may not be able to achieve. For example, a larger company, because of a high volume of purchases, may be able to negotiate a lower price from its fuel supplier than would be available to a smaller company. Cost savings resulting from increased efficiency can be passed to the utility's customers through lower electricity rates.

Whereas utility executives argue that a merger or acquisition will improve the efficiency of the new company, experience indicates that efficiency improvements are difficult to achieve. One study reported that only 15 percent of mergers and acquisitions have achieved the financial objectives that were expected.[18] Incomplete or underdeveloped plans to integrate the companies was noted as a major factor for not achieving the objectives.

A company's strategic objectives are also a factor in the decision to merge. "Does the merger complement or enhance the strategic objectives of the company" is a question asked by company executives in identifying merger partners. Strategic objectives are company specific and depend upon the merging companies' particular circumstances. Building on core competencies, diversifying power generating capability, and acquiring additional managerial and technical expertise are mentioned often as reasons. All of these strategic reasons, however, relate to the desire to remain competitive in the rapidly changing electricity industry.

Mergers Creating Large Vertically Integrated Power Companies

The structure of the IOU segment of the electric power industry is changing in fundamental ways. Industry statistics indicate that IOUs are becoming larger and ownership of generation capacity among IOUs is becoming more concentrated than perhaps any time since the early 1930s. The two mergers pending regulatory approval that are discussed below provide good examples.

American Electric Power (AEP) and Central and South West Corporation (CSW): AEP, based in Ohio, is one of the Nation's largest vertically integrated electric utilities. AEP provides energy to 3 million customers in States in the Midwest. CSW is also a large public utility holding company serving 1.7 million customers in 4 States in the Midwest and Southwest.

In December 1997, AEP and CSW announced an agreement to merge. This merger will be the largest electric-to-electric merger to date, and the new company, which will be named American Electric Power Company, Inc., will be the largest utility holding company in the United States in terms of generating capacity. The combined company will have over $30 billion in assets, and it will provide energy to approximately 4.7 million customers from Michigan to Texas. The company anticipates net savings related to the merger of approximately $2 billion over 10 years from the elimination of duplication in corporate and administrative programs, greater efficiencies in operation and business processes, increased purchasing efficiencies, and the combination of the two work forces.

Each company has acknowledged that the combined company provides the capitalization, resources, and expertise for entry and growth into new areas within the industry. For example, they recognize that wholesale power markets are a growing segment of the industry, and they plan to expand their wholesale electric power activities with an objective of becoming a top-tier national energy trading and marketing business. With more than 38 gigawatts of generating capacity in place throughout the Midwest and Southwest, the new company will increase its capability to sell electricity in wholesale markets in a large region of the country.

Even though the merger was announced over a year and a half ago, it is still being evaluated by the Federal Energy Regulatory Commission (FERC). Because of the size of the combined company with its vast generation capacity and transmission systems, the effect of the merger on competition and the potential for too much market power are being closely examined. Many organizations

[18] Anderson, James, "Making Operational Sense of Mergers and Acquisitions," *The Electricity Journal*, Vol. 12, No. 7 (August / September 1999).

have submitted comments protesting the merger as anti-competitive. To alleviate some of these concerns, AEP has committed to turn its transmission assets over to an independent regional transmission organization. Regional transmission organizations—a concept being explored by the FERC—would have utilities that own transmission systems transfer the operation and perhaps the ownership of the transmission system to independent companies. The move may eliminate potential market power issues by reducing the company's ability to restrict access to the transmission grid, although an open access transmission tariff submitted to the FERC on behalf of the combined company should also help. Recently, the FERC accelerated the schedule for review of this merger, and its goal is to act on the merger in early 2000.

New Century Energies and Northern States Power: This merger was announced March 25, 1999. The CEOs of both companies cited the need to expand beyond a mid-size company to succeed in today's restructured electricity market. Officials of New Century Energies had stated that the company needed to double its size in order to stay competitive in the energy market. To carry out this objective, the companies that started New Century Energies will have merged twice assuming that this merger is completed.

New Century Energies was created in August 1997 with the merger of Public Service Company of Colorado and Southwestern Public Service. New Century Energies has about $6.6 billion in assets and serves approximately 1.5 million electricity customers and 1.0 million natural gas customers. In March 1999, approximately 18 months after New Century Energies was created, it announced plans to merge with Northern States Power (NSP). NSP is predominantly an electric utility with a small natural gas distribution business. It has about 1.5 million retail electricity customers in the northern midwest States and about 0.5 million retail natural gas customers. If this merger is completed, the new company, which will be called Xcel Energy Inc., will have approximately $15 billion in assets, and it will have power generation capacity covering 12 midwestern and southwestern States. New Century Energies will have achieved its objective of doubling in size in about 2-3 years from when the company was originally formed.

Operations of the merged company will stretch from Mexico to the Canadian border. The combined company will have a total generating capacity of 21.7 gigawatts, of which 15.1 gigawatts will be controlled by regulated electric utility subsidiaries in the United States. The new company will be one of the 10 largest electric utility holding companies in terms of generating capacity. The company expects the merger to result in net cost savings of approximately $1.1 billion over the first 10 years of operation.

The motivation for this merger was to strengthen the company's position to compete in the emerging electric power market, and to build its natural gas business. Combined, the new company will have a large retail natural gas market. NSP also owns Viking Gas Transmission Company, a natural gas transmission company. The large retail market for electricity and natural gas and ownership of a gas transmission company will make Xcel Energy Inc. one of the growing number of diversified energy companies (i.e., combined electric and natural gas suppliers) operating in the United States today.

Mergers Creating Large Regional Energy Delivery Companies

Many States are opening their electricity industry to retail competition by unbundling electricity supply from transmission and distribution. Retail customers will be free to choose their electricity suppliers, but they will use local electricity distribution systems to receive their electricity. Some companies have chosen not to compete in electricity generation and sales and have divested their power generation assets. Instead they will specialize in delivering electricity. This means the utility will provide the equipment and services to transport electricity to customers but will not produce or sell electricity. Electricity prices will be determined in competitive markets, but prices for transmission and distribution services will continue to be regulated.

It is relevant to note that similar to unbundling practices in the electric power industry, many States are unbundling natural gas supply from gas delivery. Retail customers will be free to choose their gas suppliers, but they will continue to use the sole local distribution companies in their area.[19] For this reason, some utilities will be specializing in the delivery of both electricity and natural gas to retail customers, calling themselves "energy delivery companies."

[19] In many States, industrial and commercial retail customers have been choosing their natural gas suppliers for some time. The movement now is to give this option to residential customers.

Even though energy delivery will be regulated and not subject to a competitive market, many utilities see a need to grow by merging. Some believe that competitive pressures in power generation and sales will force distribution utilities to keep operating costs down as retail customers seek lower electricity and delivery costs. A merger will create a larger customer base, which will support increased investments in systems and new technology that will help lower the costs of servicing the customers. Also, to offset revenue losses from exiting the power generation business, a merger will increase the combined company's revenue stream and lower its operating costs by eliminating redundant functions.

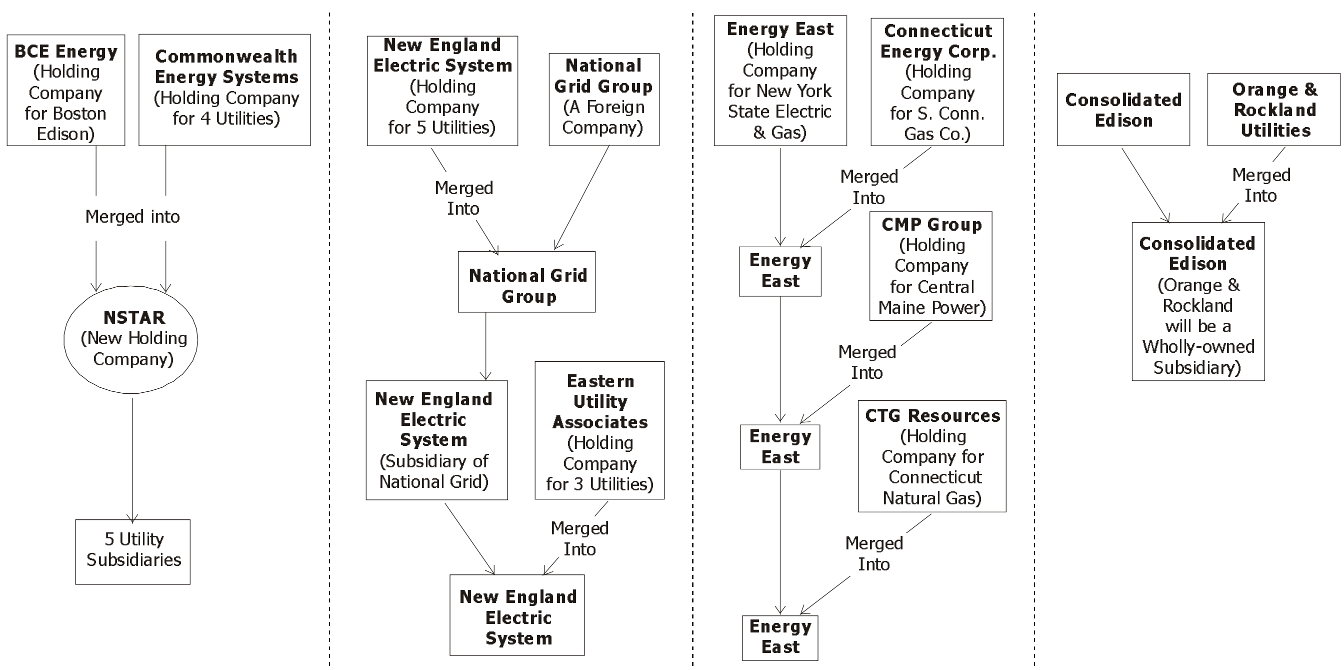
Companies specializing in energy delivery are mostly in the northeast United States. States have deregulated the electricity industry there, bringing retail competition to the region. Most utilities in the region have divested all or a significant portion of their power generation assets. Many mergers have been announced or completed as small and mid-sized distribution utilities seek to increase market share and strengthen their companies. Since the beginning of the year, seven mergers have been announced or completed in the Northeast (Figure 5). Four larger regional energy delivery companies have resulted from these mergers.

BCE Energy and Commonwealth Energy Systems: BCE Energy, parent of Boston Edison, and Commonwealth Energy Systems, a holding company with four gas and electric utility subsidiaries, announced in December 1998 that they will merge. The new company will be named NSTAR. BCE Energy's goal is to grow to 2 million customers, which they believe are needed to be competitive in the region. The combined company will have about 1.3 million customers, which suggests that another merger involving the new company may soon take place.

On a small scale, this merger illustrates the growth of combined electricity and natural gas companies. Both BCE Energy and Commonwealth Energy Systems have retail natural gas businesses. Both companies believed in the importance of having the ability to meet customers' needs for both gas and electricity. They noted quite a few areas where electricity and gas customers of the combined company overlap (e.g., customer billing), which will provide the opportunity to lower administrative costs in delivery systems and, perhaps, to improve services in other ways.

New England Electric System, National Grid Group, and Eastern Utility Associates: Also in December 1998, New England Electric System (NEES) and National Grid

Figure 5. Overview of Recent Merger Activity in the Northeast Region of the United States



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Group announced a merger of the two companies. This is one of two pending mergers involving electric utilities in which one of the merging companies is foreign-owned. NEES is New England's second largest electric utility. It was one of the first electric utilities to divest its generation assets and become an electricity delivery business entirely. National Grid Group is the owner and operator of the England and Wales high-voltage transmission network. National Grid Group is interested in expanding in the emerging U.S. electricity market and views this merger as a base operation for possible further growth in the United States.

This is an interesting merger, not only because National Grid is foreign-owned, but because it is a company specializing in operating transmission systems in a competitive environment, which is similar to what NEES faces in New England as an electricity delivery company. This matching of interest and capabilities is probably one of the reasons for the merger. Both companies believe that NEES will benefit from National Grid Group's experience in operating an electric power transmission system.

Following close behind the announcement of the merger with National Grid Group, NEES announced in May 1999 its intention to merge with Eastern Utilities Associates (EUA). EUA is a public utility holding company based in Boston whose subsidiaries include transmission and distribution utilities in Massachusetts and Rhode Island. EUA recently divested its generation assets and, like NEES, will concentrate on electricity transmission and distribution. The merger strengthens both companies in the energy delivery business in New England, and EUA was interested in growth in the region to create a stronger and more competitive company. The merger of these two relatively low-cost utilities will create, it is believed, a more efficient transmission and distribution company. This merger is not contingent upon NEES's completion of the merger with National Grid Group. According to National Grid officials, it fits into their plans for growth in the U.S. market and it has their full support.

Energy East, CMP Group, and Two Natural Gas Companies: Rounding out the surge of utility mergers in New England, Energy East, parent of New York Electric and Gas, and CMP Group, parent of Central Maine Power, announced in June 1999 that they will combine the companies. To expand its gas operation and presence in New England, Energy East recently acquired Southern Connecticut Gas Company, a small natural gas company. Before that acquisition, Energy East and CMP Group had created a gas distribution joint venture. Now Energy East's merger with CMP further expands its electricity and gas distribution operations in New England, making it one of the major energy delivery companies in the region. According to Energy East officials, the company is likely to have more acquisitions in the region.

Consolidated Edison and Orange and Rockland Utilities: Consolidated Edison (ConEd) supplies electric services in all of New York City and one county outside the city. It has a smaller market for natural gas customers in the city. ConEd has divested most of its power generation assets. Orange and Rockland provides electricity and gas services to three large counties in the State of New York and will divest all of its power generation capability. Basically these companies are now distribution-only companies serving customers in New York City and surrounding areas. The strategy of both companies was to enlarge their transmission and distribution business and customer base. The merger of the companies contributed to that goal. They expect to improve operations and achieve efficiencies from the merger. Because both companies have combined electric and gas operations, there may be opportunities for improved service and efficiencies in both areas.

Independent Power Producers Getting Bigger by Acquiring Electric Utilities

IPPs are a growing segment of the electric power industry. Spawned by the deregulation of power generation and the opening of wholesale power markets to competition, many IPPs have built or are building new merchant power plants throughout the United States. Some IPPs have purchased generation assets from IOUs and recently a few IPPs have used mergers to grow. For the first time in the history of the electric power industry, IPPs are now acquiring IOUs. One such acquisition was recently completed, and another is pending.

CalEnergy Company and MidAmerican Energy: CalEnergy is an IPP that owns generation capacity in the United States and globally. Before the merger, CalEnergy managed and owned interest in over 5,000 megawatts of power generation facilities, including 20 generation facilities it operated. MidAmerican Energy Holding Company is the parent company for MidAmerican Energy, a regulated electric utility. MidAmerican

Energy provided retail electricity service to customers in Iowa, and parts of Illinois and South Dakota. It owns more than 4,400 megawatts of generation capacity. The merger, which was completed in March 1999, was the first acquisition of a U.S. regulated utility by an IPP. Although CalEnergy acquired MidAmerican Energy Holding Company, CalEnergy reincorporated in Iowa under the name MidAmerican Energy Holding Company. In effect, MidAmerican is a new company.

MidAmerican Energy Company, one of the largest utilities in Iowa, will be a wholly-owned subsidiary of MidAmerican Energy Holding Company, and it will continue to generate power and provide energy delivery. This merger gives CalEnergy a foothold in the growing Midwest power market, a location where the company has a long-term business objective. CalEnergy's experience in global competitive markets can be applied to the competitive market in the Midwest.

AES Corporation and CILCORP: In late 1998, AES and CILCORP announced a merger. AES is also a global power company and one of the largest IPPs in the United States. It owns about 7,300 megawatts of U.S. generation capacity, and the merger with CILCORP will give it an additional 1,200 megawatts located in the Midwest power market. CILCORP is an energy services company whose largest subsidiary is Central Illinois Light Company, an established gas and electric utility in Central Illinois. After the merger, CILCORP will become a wholly-owned subsidiary of AES. Like CalEnergy, AES is interested in expanding its operations and was particularly interested in entering the competitive market in the Midwest.

Some industry analysts see these two mergers as the start of a trend in which big independent generation companies may favor buying small and mid-sized utilities with favorably positioned generation assets, because it is cheaper than entering into competitive bidding for generation assets that utilities are seeking to divest and cheaper than building new generation plants. Also, merging with an established company is a reasonably quick way to obtain a presence in new markets. On the other hand, with the current wave of mergers and acquisitions, small to mid-size utilities are quickly being combined into larger companies, and opportunities are becoming limited.

Foreign Ownership of Investor-Owned Electric Utilities

For years, U.S. utilities have been expanding overseas by investing in foreign energy companies and foreign electric utilities. Recently, a reversal in this trend occurred when two foreign-owned energy companies announced that they will acquire U.S. electric utilities.

PacifiCorp and Scottish Power: In December 1998, Scottish Power announced that it was buying the U.S. utility PacifiCorp. PacifiCorp is a large utility holding company for Pacific Power and Utah Power. Scottish Power is Scotland's largest utility. Previously government-owned, it was privatized in 1991. Scottish Power, seeing opportunities in the U.S. electricity industry and eager to enter the market, had been shopping for a U.S. electric utility for about a year prior to this announcement. While foreign companies have invested in U.S. power plants in the past, Scottish Power's purchase of PacifiCorp will be the first purchase of an entire U.S. utility holding company by a foreign company.

Through this acquisition, Scottish Power gains access to California's energy market, and it could redirect PacifiCorp into the power marketing area, an area where Scottish Power has some expertise. Scottish Power's CEO suggested that his company will apply its experience in deregulated markets to help PacifiCorp improve customer service and achieve cost reductions.

New England Electric System and National Grid Group:[20] The other acquisition involving a foreign-owned company is National Grid Group's acquisition of NEES. This acquisition was mentioned earlier in the context of the development of regional energy delivery companies. Both this acquisition and Scottish Power's acquisition of PacifiCorp have recently received approval from the FERC. Approval also is required from several other Federal agencies and from the relevant State public utility commissions (see Table 6).

These two mergers are examples of an emerging global energy market. In some respect, they pave the way for further acquisitions by multinational utility companies of U.S. utilities that may be viewed by foreign companies as attractive investments for a number of reasons.

[20] National Grid Group is the largest privately-owned independent transmission company in the world, and one of the top 100 companies in the United Kingdom.

Table 6. Government Agencies Responsible for Reviewing Mergers and Acquisitions Involving Electric Utilities

Government Agency	Authority	Type of Review
Department of Justice or Federal Trade Commission	Section 7 of the Clayton Act, Hart-Scott-Rodino Antitrust Improvements Act	Examines mergers that may substantially lessen competition or tend to create a monopoly.
Federal Energy Regulatory Commission	Federal Power Act of 1935, Department of Energy Reorganization Act of 1977, Energy Policy Act of 1992	Examines mergers and other combinations to assure markets and access to reliable service at reasonable prices.
Internal Revenue Service	16th Amendment to U.S. Constitution (1913)	Determines amount of tax liability for combination.
Nuclear Regulatory Commission	Atomic Energy Act, Energy Reorganization Act of 1974, Energy Policy Act of 1992	Approves transfer of ownership of nuclear facilities.
Securities and Exchange Commission	Public Utility Holding Company Act of 1935 (PUHCA)	Assures compliance with PUHCA provisions and protection of shareholder interest.
State Public Utility Commission, State Attorney General Office	Various State Laws	Full review may include: antitrust, market power, stranded costs, rates, and demand-side management. The State has the authority to allocate merger savings between ratepayers and shareholders.

Sources: Energy Information Administration, *Natural Gas 1998: Issues and Trends*, DOE/EIA-0560(98) (Washington, DC, June 1999), Chapter 7; and M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis* (Westport, CT: Praeger Publishers, 1994).

First, the U.S. economy is expanding when other parts of the world are in recession. Asia's downturn, for example, cooled interest in risky ventures in that part of the world. The U.S. economy is viewed as a stable, safe, and reliable investment. Second, restructuring and de-regulation of the U.S. electricity industry provide good investment potential for companies that can operate power systems efficiently and compete in the new environment.

Regulatory Review and the Approval Process

Electric utility mergers or acquisitions of substantial size go through a review process involving a number of Federal and State government agencies (Table 6). At the State level, the public utility commission or its equivalent reviews the merger for potential anti-competitive effects and potential cost savings. States may also review the merger's affect on a utility's stranded costs,[21] an issue brought on by industry deregulation. Because most electric utility operations cross State boundaries, it is not uncommon for multiple States to review a merger. The extent and depth of the review can vary widely between States, depending on the merger's expected impact in the State and the resources available to conduct an evaluation.

Federal review of a proposed merger may include up to five different agencies. Either the Federal Trade Commission (FTC) or the Antitrust Division of the Department of Justice (DOJ) could conduct a review to determine whether the merger is consistent with anti-trust laws. Recently, the Antitrust Division of the DOJ, rather than the FTC, has reviewed electric utility mergers, but for most electric utility mergers the DOJ relies on the FERC to take the lead in evaluating the competitive effects of the merger. The DOJ limits its role to participation as an interested party.[22] The Securities and Exchange Commission (SEC) can become involved

[21] In general, stranded costs are historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. Stranded costs are also known as stranded investments, stranded commitments, and transition costs.

[22] M.W. Frankena and B.M. Owen, *Electric Utility Mergers, Principles of Antitrust Analysis,* (Westport, CT: Praeger Publishers, 1994).

in a merger or acquisition when a holding company gains control of 10 percent or more of the voting securities of another electric utility. If that is the case, the SEC reviews the merger for compliance with requirements of the Public Utilities Holding Company Act of 1935 (see Appendix A). The Nuclear Regulatory Commission (NRC) reviews a proposed merger or acquisition when it involves the transfer of a nuclear power plant operating license.

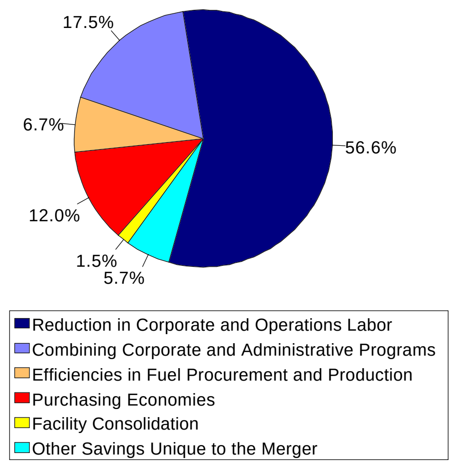
Of all Federal Government agencies involved in reviewing a proposed merger between electric utilities, the FERC's review is probably the most extensive, covering the merger's potential effects on competition in the industry, electricity rates to customers, and regulation. The FERC sometimes will request merger applicants to prepare special reports showing the merger's effect on market power or the cost savings and efficiencies that are expected from the merger. These reports and other documents, such as public comments about the merger, are available on the Commission's website (www.ferc.fed.us). Depending on the level of public interest, the size of the merging companies, and the merger's potential impact on the industry, the FERC may hold public hearings to obtain information and to discuss important issues associated with the merger.

Cost Savings and Other Benefits Derived from Mergers

Controlling and reducing costs is the most frequently used and strongest justification for merging. Companies attempting to merge always present estimates of cost savings to the reviewing agencies for consideration. As regulatory authorities, government agencies are looking to pass these savings on to the consumer by lowering electricity rates. Because of unanticipated events and circumstances, however, the cost savings expected from the merger may not be fully attainable. Difficulties in integrating the operation and culture of two large companies, for example, might require more resources than originally expected, and efficiencies may not materialize.

It is difficult to generalize about the effectiveness of a merger in reducing costs. Some mergers may be very effective while others may not. For most mergers, the majority of cost savings are expected to be in labor cost reductions. Usually, over 50 percent of the expected savings will come from a reduction in corporate and operations labor (Figure 6). Consolidation of corporate and administrative programs, such as customer billing, is another potential area for significant cost savings.

Figure 6. Estimated Cost Savings from a Merger
(Percent of Total Savings)



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels, compiled from pre-merger testimony given to the Federal Energy Regulatory Commission for five mergers.

Two case studies of mergers completed in 1993 and 1994 were conducted to determine whether the expected cost savings were actually achieved. These mergers were selected, in part, to obtain a pre-merger and post-merger view of the companies. The case studies also looked at the merging companies' objectives and whether they were realized. Following is a summary of the results of the studies. Appendices C and D contain a full discussion of the case studies.

Case Study of the Cincinnati Gas & Electric and PSI Resources Merger: In 1994, Cincinnati Gas & Electric Company (CG&E) and PSI Resources, Inc. merged to form CINergy Corporation (CINergy). The primary objectives of the merger were to create a larger and more efficient utility to better meet the challenges of competition and to receive the benefit of $750 million in merger-related savings, which could be passed through to both ratepayers and owners of CINergy. Appendix C contains a full discussion of the CINergy case study.[23]

[23] The study was conducted using public data gathered from FERC Form 1, Securities and Exchange Commission 10-K filings, and company annual reports. Conclusions about the effects of the merger are based only on the data available from these sources.

The merger succeeded in creating a larger company, primarily because the companies were approximately equal in size. In fact, the merger produced the thirteenth largest electric utility holding company in the Nation in 1994. From 1994 to 1997, electricity sales of the combined company more than doubled from pre-merger years, and operating revenues increased by 43.5 percent. Wholesale electricity sales, which were declining slightly before the merger, increased fivefold. By 1997, CINergy ranked seventh in the Nation among electricity commodity trading companies, as measured by purchases from power marketers. During 1997, the New York Mercantile Exchange selected CINergy to be one of only four electricity futures market trading hubs in the Nation. The merger has to be given much of the credit for these growth accomplishments, because it resulted in the integration and upgrade of, and customer open access to, the transmission systems of PSI Energy, Inc. and CG&E.

The merger also resulted in operating efficiency gains under several measurements. By 1997, real operating and maintenance costs had declined by 11 percent from their 1994 level, and customer expenses had declined by 12 percent over the same period. Worker efficiency within the electric departments also apparently increased, although this conclusion is less certain due to the probable shift of some administrative functions housed within electric utility departments before the merger to a new nonregulated subsidiary of CINergy, CINergy Services, Inc. In any case, megawatthour sales per electric utility department employee increased by a factor of four between 1994 and 1997, and the average number of customers served per electric department employee more than doubled.

The merger has had little effect on retail electricity rates. Retail electricity rates equal the utility's revenue per kilowatthour of sales to retail customers. Average electricity rates (adjusted for inflation) declined by 1.5 percent annually before the merger and continued to decline at the same rate after the merger. Common stock shareholders of CINergy experienced a boost in common stock prices in the early years after the merger and in total returns on common equity. However, the effects of the merger had dissipated by 1998, and total common stock shareholder returns were negative in that year.

There was evidence of merger savings over the 1994-1997 period from workforce reduction, deferral of the construction of new generation capacity, and greater efficiency in electricity production (due to coordinated generation plant dispatch). These observed savings make probable total merger savings of approximately $950 million over the decade following the merger, which is within the range provided by CINergy's two merger savings estimates, namely, $750 million to $1.5 billion. Merger-related costs are now included within CINergy's financial statements over the period 1994-1997, and therefore are known to be $225 million. Thus, net merger savings are likely to be about $725 million, which compares well with CINergy's original public announcement in December 1992 of $750 million of merger savings. At that time, CINergy did not include an estimate of costs associated with the merger.

Case Study of the Entergy and Gulf States Utilities Merger: In 1993, Gulf States Utilities Company (GSU) merged into Entergy Corporation (Entergy). GSU was about one-third to one-half the size of Entergy when it merged, but the merger created the second largest electric utility in the Nation. The primary objectives of the merger were to save an estimated $1.7 billion in costs over 10 years, which could be passed through to both ratepayers and stockholders, and to better position the combined company for growth and profitability in the emerging competitive industry. The merger responded to a need by GSU to better its financial condition because State regulatory agencies had disallowed recovery of a large portion of construction and related costs associated with its one nuclear power plant at River Bend. The merger was also consistent with an aggressive acquisition policy being implemented by Entergy at the time. Appendix D contains a full discussion of the Entergy case study.[24]

The merger succeeded in stimulating growth in both retail and wholesale kilowatthour sales over the first 4 years after the merger (1994-1997) by the five operating utilities of the combined company. Growth in operating revenues was slowed, however, primarily because of a sharp decline in retail customer rates over this period, at least partly due to concessions made by the merging entities to various regulatory commissions when seeking approval of the merger. Nominal retail customer rates declined by 9.1 percent over the 1994-1997 period; retail electricity rates for the original operating utilities of Entergy declined by 3.1 percent over the same period. As a whole, Entergy/GSU's average retail rates fell

[24] The study was conducted using public data gathered from FERC Form 1, Securities and Exchange Commission 10-K filings, and company annual reports. Conclusions about the effects of the merger are based only on the data available from these sources.

faster than the average retail electricity rates for all IOUs over this period.

Operating efficiency at Entergy / GSU was boosted by the merger, mostly due to the consolidation of purchasing, customer service, and administrative functions, the coordination of generation dispatch, the operation of GSU's one nuclear plant by Entergy after the merger, and the functional integration of GSU along the lines of Entergy's operations. Real operations and maintenance (O&M) costs per net generation kilowatthour for Entergy / GSU declined by 13 percent over the first 4 years after the merger, as compared with an increase of 2.5 percent over the 2 years before the close of the merger. Other measures also showed efficiency improvements for Entergy / GSU: megawatthour sales per electric department employee increased by 168 percent; the average number of customers served per employee increased by 147 percent; and real customer expense per customer declined by 27.3 percent.

The ratepayers received nearly all the benefits from the merger. GSU's stockholders at the time of the merger also may have received a premium price when converting their stock into Entergy's. However, owners of Entergy's common stock after the merger did not experience improved profitability. Net electric operating income from the five operating utilities of Entergy fell by 13 percent over the first 4 years after the merger. Net earnings per common share fell from $2.62 to $1.03 in 1997, and dividends were cut in 1998 from $1.80 to $1.50 per share. Average total returns to the common stockholder (dividends and stock price appreciation) were only 6.6 percent over the 1994-1998 period, approximately equivalent to the yield of a long-term Treasury Bond that has no risk. During the middle of 1998, the CEO of Entergy, who was responsible for the merger and Entergy's aggressive acquisition policy, was replaced and a new strategy was put in place. Its purpose was in part to remedy reliability and customer service problems suffered in its core domestic utility operations due to cost-cutting measures implemented over the past several years.

Based on an examination of public data, it is likely that Entergy will achieve its estimated merger cost savings in the categories of fuel costs and nonfuel O&M expenses. Savings associated with the costs of fossil fuels for electricity generation at GSU, after the end of the 4 years following the merger, were right in line with expectations. Merger savings associated with nonfuel O&M expenses at GSU over the 4 years after the merger were already higher than estimated for the first 5 years, and GSU was expected to accrue more than 86 percent of the merger savings in this category. The other Entergy major utilities had achieved substantial savings in nonfuel O&M expenses over the first 4 years after the merger, far greater than that estimated for the merger, primarily because of Entergy's reorganization and restructuring of these utilities which began in the third quarter of 1994.

Recorded merger costs were slightly higher than estimated by Entergy when the merger was announced, and even higher when merger-related capital costs and pre-1994 merger transaction costs are counted. Total merger-related costs probably will be approximately $194 million. However, with merger savings in the nonfuel O&M category also running higher at GSU—and recognizing that the nature of the cost-saving measures that were implemented resulted in permanent savings—it is likely that Entergy / GSU's estimated net merger savings associated with fuel costs and nonfuel O&M expenses (estimated at $849 million and $673 million, respectively) will be realized over the 1994-2003 period. These savings, which total $1.5 billion, compare favorably with Entergy's 10-year pre-merger estimated savings of $1.7 billion.

4. Convergence Mergers

Increased competition that has emerged from deregulation of the electric and gas industries has, in part, created an environment in which the convergence of the two industries can flourish. Increased competition has pressured electric utilities and natural gas companies to combine operations in order to become more efficient, to diversify products, to share expertise and experience in energy markets, and to take advantage of the growing use of natural-gas-fired power plants. Combining electric utilities and natural gas companies has been called convergence of the industries, and many companies that once sold only electricity or natural gas in retail markets now sell both electricity and natural gas, or are involved in other aspects of both industries.

A combined electric and natural gas utility is not something new to the industry. Many investor-owned utilities (IOUs) sell both electricity and natural gas to retail customers. What is new about the recent wave of mergers is that many of them are between electric utilities and natural gas production, processing, or interstate pipeline companies. These types of mergers expand greatly the business opportunities for electric utilities.

From 1997 through September 1999, 20 convergence mergers involving companies with assets valued at $0.5 billion or higher have been completed or are pending completion (Table 7).[25] No one knows for certain how long this trend will continue, but many industry observers agree that more convergence mergers will take place as deregulation of the electric power industry continues and electric and natural gas companies seek to diversify their businesses.

Strategic Benefits of Convergence Mergers

The natural gas industry has a relatively complicated structure which, depending on one's classification scheme, may consist of four major corporate segments (Table 8). Some of the major natural gas companies are vertically integrated, having exploration and production, pipelines, storage, local distribution, and marketing components. The majority of the companies are not vertically integrated but specialize in one or two areas. Local distribution companies (LDCs) are the largest segment of the industry, with approximately 1,400 LDCs operating in the United States. The benefits to an electric utility of a convergence merger depend on where the gas company is located in the production cycle. An analysis of the current wave of convergence mergers shows that the benefits of the merger generally fall into one or more of the following areas.

Strengthen Wholesale Marketing and Trading Operations: Deregulation of the electricity and natural gas industries has created spot markets for wholesale electricity and natural gas, as well as markets for buying, selling, and trading financial instruments for risk management. In competitive commodity markets, prices for the commodities (in this case, electricity or natural gas) are sometimes volatile. Risk management, such as buying futures contracts for electricity, helps reduce the risk of price volatility. Many electric utilities and natural gas companies realize that there are similar and related techniques for electric and natural gas marketing and trading in spot markets, and are merging to form larger organizations specializing in electricity and natural gas. This provides the opportunity to sell a diversified line of products to their customers, and it can help lower administrative and processing costs. It also facilitates arbitrage between electric power and natural gas prices.

One of the most frequently cited reasons for a convergence merger is that the gas company's experience in marketing and trading can be transferred to an electric company that is relatively new to working in competitive markets and commodity trading. The gas industry has been deregulated since the 1980s, and over that time surviving gas companies have developed skills and experience in working in competitive energy markets.

[25] A convergence merger is defined as a merger in which one company's primary business activity is electricity generation, transmission, and/or sales and the other company's primary business activity is natural gas production, processing, transportation, and/or sales.

Table 7. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through September 1999

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Mergers Creating Vertically Integrated Energy Companies					
Pacific Gas & Electric Corporation	Pacific Gas & Electric Corp. Valero Energy Corp. (Valero Natural Gas Company)	Electric/Gas Gas	PG&E Corp.: $30.6 Valero: $1.5 Total: $32.1	Completed in 1997	PG&E Corporation is a large electric and natural gas company. Valero is a natural gas process and gas transportation and storage company. This acquisition increases PG&E's presence in the Texas natural gas industry.
Reliant (formerly Houston Industries)	Reliant NorAm Energy	Electric Gas	Reliant: $12.3 NorAm: $4.0 Total: $16.3	Completed in 1997	Houston Industries is a holding company; Houston Light & Power, a vertically integrated electric company, is the principal subsidiary. NorAm Energy owns subsidiary companies engaging in wholesale electricity and gas marketing, interstate gas transmission, and retail natural gas distribution.
Enron	Enron Portland General Corp. (Portland General Electric)	Gas Electric	Enron: $23.4 Portland: $3.3 Total: $26.7	Completed in 1997	The merger between Enron, an integrated natural gas company, and Portland General Electric was the first merger between a predominantly natural gas company and an electric utility. It marked the beginning of the convergence trend in the industry and the creation of large electricity and natural gas companies.
Duke Energy Corporation	Duke Power Company PanEnergy Corporation	Electric Gas	Duke Power: $13.5 PanEnergy: $8.6 Total: $22.1	Completed in 1997	In June 1997, Duke Power Co., one of the Nation's leading electric utilities, and PanEnergy Corporation, a natural gas pipeline and marketing company, completed a merger creating Duke Energy Corporation. Duke Energy Corporation has an aggressive growth strategy, and its objective is to become a large diversified global energy company.
	Union Pacific Fuels	Gas	UP Fuels: $1.4	Completed in 1999	Duke Energy Field Services, a component of Duke Energy Corporation, purchased the natural gas gathering, processing, fractionation, and liquids pipeline business of Pacific Resources (known as Union Pacific Fuels). This purchase expands Duke Energy's capability in the production of natural gas liquids and other areas in the natural gas business.
CMS Energy	CMS Energy (Consumer Energy) Panhandle Eastern Pipeline	Electric/Gas Gas	CMS Energy: $11.3 Panhandle: $2.0 Total: $13.3	Completed in 1999	CMS is a diversified energy company having both electricity and natural gas operations. PanHandle is a natural gas pipeline company in the Midwest. Because PanHandle's pipelines connect to CMS's gas distribution and storage, this merger was a good strategic move. CMS noted that gas-fueled electricity generation continues to grow in the Midwest, and this merger improves its effort to be a major player in the gas supply market.
Dominion Resources	Dominion Resources (Virginia Power) Consolidated Natural Gas	Electric/Gas Gas	Dominion: $17.5 Consolidated: $6.4 Total: $23.9	Pending	Dominion Resources is predominantly a power company owning regulated and unregulated power generation assets. Consolidated Natural Gas is a large producer, transporter, distributor, and retail marketer of natural gas. This merger will create one of the Nation's largest integrated electric and natural gas companies.

See notes at end of table.

Table 7. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through September 1999 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Mergers Creating Energy Distribution Companies					
Dynegy	Illinova Dynegy	Electric/Gas Gas	Illinova Corp: $6.4 Dynegy Inc: $5.3 Total: $11.7	Pending	Illinova is an energy service company; its primary subsidiary is Illinois Power, an electric and natural gas utility. Dynegy Inc. is a marketer of energy products and services. It grew from primarily a natural gas marketer to a full energy service marketing company.
Puget Sound Energy	Puget Sound Power & Light Co. Washington Energy Co.	Electric Gas	Puget Sound: $3.3 Washington: $1.0 Total: $4.3	Completed in 1997	This merger creates one of the largest combined electric and natural gas utilities in the Northwest. The merger expands Puget Sound Power & Light into the natural gas distribution business.
TXU (formerlyTexas Utilities Co.)	Texas Utilities Co. ENSERCH (Lone Star Gas)	Electric/Gas Gas	Texas Utilities: $21.4 ENSERCH: $3.2 Total: $24.6	Completed in 1997	Texas Utilities is a combined electric and natural gas company. It owns two electric utilities in Texas. ENSERCH is a natural gas distribution and pipeline company. It owns Lone Star Gas Company, the largest natural gas distribution company in Texas. This merger significantly expands the customer base of the new combined company.
KeySpan Energy	LILCO (Long Island Lighting Co.) Brooklyn Union Gas	Electric/Gas Gas	LILCO: $4.2 Brooklyn Union: $2.3 Total: $6.5	Completed in 1998	The merger of LILCO, an electric utility, and Brooklyn Union, a gas utility, creates a regional energy distribution company serving primarily New York.
Sempra Energy	ENOVA (San Diego Gas and Electric) Pacific Enterprises (Southern California Gas)	Electric/Gas Gas	ENOVA: $5.2 Pacific: $5.0 Total: $10.2	Completed in 1998	The merger of San Diego Gas & Electric, primarily an electricity distribution company, and Southern California Gas, a gas distribution company, creates one of the largest regulated energy distribution companies in the United States.
NIPSCO Industries	NIPSCO Industries (Northern Indiana Public Service) Bay State Gas	Electric Gas	NIPSCO: $3.7 Bay State: $0.8 Total: $4.5	Completed in 1999	NIPSCO is a holding company for Northern Indiana Public Service, an electric and gas distribution utility. Bay State is a gas distribution utility. The merger expands NIPSCO's energy distribution market.
Energy East	Energy East (New York State Electric & Gas) Connecticut Energy (Southern Connecticut Gas)	Electric/Gas Gas	Energy East: $4.9 Conn. Energy: $0.5 CTG Resources: $0.5 Total: $5.9	Pending	Energy East, the parent company of New York Electric & Gas, has chosen to focus the company on energy delivery. The merger with Connecticut Energy, the parent of Southern Connecticut Gas, a gas distribution company, increases Energy East's market share in the Northeast region.
	CTG Resources, Inc. (Connecticut Natural Gas Corp.)	Gas		Pending	Connecticut Natural Gas is engaged in the distribution, transportation, and sale of natural gas in Hartford and 21 other cities and towns in central Connecticut and in Greenwich, Connecticut. This represents the third acquisition by Energy East over the past few months, further strengthening its competitive position in the Northeast.

See notes at end of table.

Table 7. Selected Mergers and Acquisitions Involving Investor-Owned Electric Utilities and Natural Gas Companies, 1997 Through September 1999 (Continued)

Combined Electric Power and Natural Gas Company	Companies Merging	Type of Business	Value of Assets (Year-of-Merger Dollars in Billions)	Status	Comments
Mergers Creating Energy Distribution Companies					
Northeast Utilities	Northeast Utilities Yankee Energy System	Electric Gas	Northeast: $2.2 Yankee Energy: $0.5 Total: $2.7	Pending	Northeast Utilities is one of New England's largest electric utility systems. Yankee Energy System, Inc. is the parent company of Yankee Gas Services Company, one of the largest natural gas distribution companies in the Northeast.
SCANA Corporation	SCANA Corp. (South Carolina Electric & Gas) Public Service Co. of North Carolina	Electric/Gas Gas	SCANA: $5.3 PS of NC: $0.7 Total: $6.0	Pending	SCANA is the parent company of South Carolina Gas & Electric. Public Service of North Carolina, Inc. is a gas utility. This merger expands SCANA's gas distribution business and energy marketing resources.
Vectren	SigCorp Inc. (Southern Indiana Gas & Electric) Indiana Energy	Electric/Gas Gas	SigCorp: $1.0 Indiana Energy: $0.7 Total: $1.7	Pending	SigCorp is a mid-size gas and electric company. Indiana Energy is a natural gas distribution and energy marketing company. This merger increases the customer base of the new combined company.
Wisconsin Energy	Wisconsin Energy Corp. Wicor (Washington Gas Co.)	Electric/Gas Gas	Wisconsin: $5.4 Wicor: $1.0 Total: $6.4	Pending	Wisconsin Energy is an electricity and natural gas holding company. It owns two operating electric utilities, Wisconsin Electric and Edison Sault Electric. WICOR is a diversified holding company operating in two industries—natural gas distribution and water pump manufacturing. This merger strengthens Wisconsin Energy's gas business and helps to make it a major regional player in the evolving electricity and natural gas markets.
DTE Energy	DTE Energy (Detroit Edison) MCN Energy Group (Michigan Consolidated Gas Company)	Electric Gas	DTE Energy: $12.1 MCN Energy: $4.4 Total: $16.5	Pending	This merger was announced in early October 1999. DTE Energy is a holding company; it's primary subsidiary is Detroit Edison, a large investor-owned electric utility. MCN Energy Group, through its subsidiary Michigan Consolidated Gas Company, is a large gas distribution company. It also has gas pipeline, processing, and marketing activities, and it has investments in electric power. The combined company will be the largest gas and electricity utility in Michigan.

Note: Table includes mergers or acquisitions in which each company had assets valued at $0.5 billion or higher at the time of the merger.

Sources: Mergers and Acquisitions were identified from trade journals, newspapers, and electric utility press releases found on their Internet websites. Values of the companies' assets were obtained from the Securities and Exchange Commission 10-K filings.

Table 8. Overview of Strategic Benefits of a Combined Electric and Natural Gas Company

Natural Gas Corporate Segments	Description	Potential Strategic Benefits to Electric Company of Combining with Natural Gas Company
Producers	Perform gas exploration and production functions. Generally market gas at the wellhead to third parties who resell the gas.	Electric company may have direct access to natural gas to fuel power plants.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Pipelines	Provide wholesale transportation/transmission function. Transport gas from the field to market area. Pipeline network facilities may include gathering, transmission, compressor, storage, and metering facilities.	Access to a reliable source of natural gas for existing gas-fired power plants.
		New gas-fired merchant power plants can be strategically built relative to natural gas pipelines.
		In general, by acquiring natural gas assets, the combined company can offer a wider assortment of energy products and services.
Local Distribution Companies	Provide retail sales and local transportation deliveries.	Cross-sell natural gas to retail electricity customers as a way to expand products and services.
		Help reduce unit costs by expanding overhead over larger customer base.
		Improve efficiencies of retail sales by combining billing and other administrative functions.
Marketers and Brokers	Engage in competitive wholesale gas sales and services. Buy and resell natural gas and gas management services to others on a deregulated basis.	Expand marketing effort and improve effectiveness of marketing by selling both natural gas and electricity to a common customer base.
		Apply gas company expertise and experience in gas marketing to electricity marketing.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Diversify Products and Expand Retail Markets: Most electric utilities believe that to remain competitive they need to offer more products and services to their retail customers. State-designed customer choice programs, which allow retail customers to select their energy suppliers, motivate utilities to differentiate their products from their competitors' products. One strategy to accomplish this is to merge with a local gas distribution utility and offer both electricity and natural gas services to customers. The idea of "one-stop shopping" appeals to some customers, and combined marketing and delivery systems can also help reduce the utility's billing, metering, and other administrative costs.

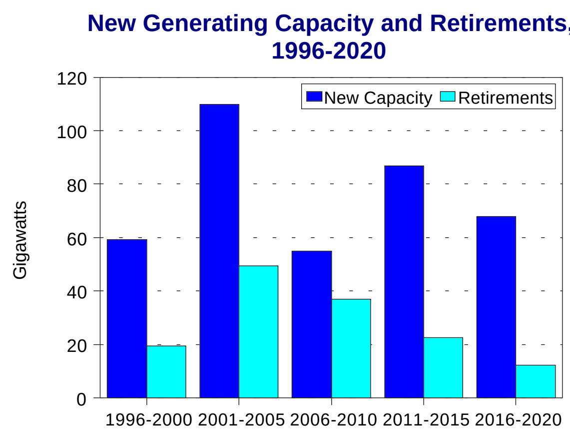
In addition to diversifying products and services, many utilities see convergence mergers as a way to increase market share, although this concept also applies to mergers involving only electric utilities. Increased market share should lower per-customer costs by spreading fixed costs over more customers. Utility distribution systems have a large fixed-cost component.

Another benefit from convergence mergers is the potential for cross-selling electricity to natural gas customers and natural gas to electricity customers. The extent to which the customer base of the merging companies does not overlap represents the potential for increasing market share by cross-selling.

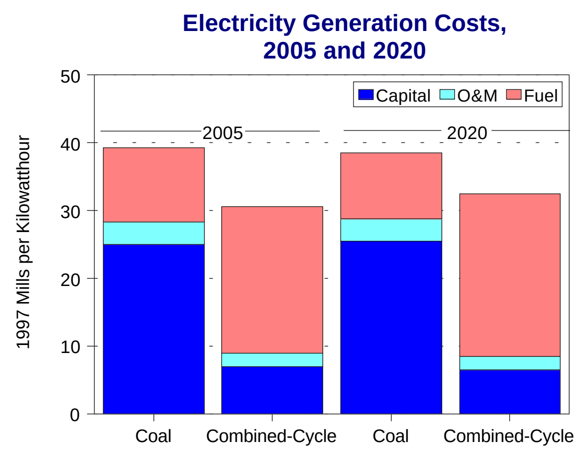
Expand and Strengthen Access to a Fuel Supply for Merchant Power Plants: Many electric utility holding companies are merging with natural gas companies that specialize in natural gas production, processing, pipeline operation, and storage. In the natural gas industry parlance these are called upstream and midstream functions. Distribution to the ultimate customer is a downstream function. Electric utility mergers with upstream or midstream natural gas companies position the new company to benefit from the growing demand for natural gas stimulated by the projected growth in gas-fired power plants across the country.

Because of the rising demand for electricity and retirement of older power generation units, 363 gigawatts of new generating capacity will be needed in the United States by 2020 (Figure 7). Between 1997 and 2020, 126 gigawatts of nuclear and fossil-steam capacity are expected to be retired. Assuming an average plant capacity of 300 megawatts, a projected 1,210 new plants will be needed to meet electricity demand and to offset retirements. Eighty-eight percent of that capacity is projected to be natural-gas-fired or dual-fired gas and oil combined-cycle or combustion turbine technology. These technologies have lower capital costs and operating and maintenance costs than other technologies, and they meet more easily local and Federal Government emissions constraints, which are expected to tighten in the future. In 1997, gas-fired power generators produced 15 percent of total electricity generation in the United States; by 2020 they are projected to produce 33 percent of the total.

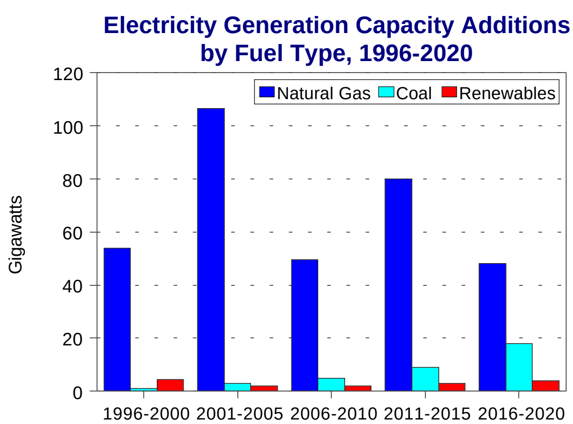
Figure 7. Projections of Growth in New Gas-Fired Power Generation, 1996-2020



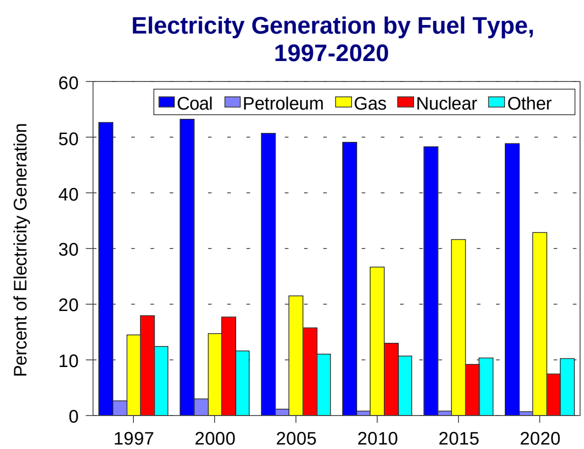
Rising electricity demand and plant retirements create a need for new generators.



New gas-fired generators could be less expensive than coal-fired generators, making them the most popular technologies for electricity generation.



More than a thousand new power generation plants could be needed by 2020, and most of them will be gas-fired.



In 1997, gas-fired generation accounted for 15 percent of total U.S. electricity generation; by 2020, gas-fired generation will account for 33 percent of the total.

Source: Energy Information Administration, *Annual Energy Outlook 1999*, DOE/EIA-0383(99) (Washington, DC, December 1998).

Electric utilities that own upstream and midstream natural gas resources will be positioned to compete for customers in growing natural gas markets brought on by the increase in demand for gas-fired plants. Also, by owning upstream and midstream gas resources, a company can expand its range of products and services and build a marketing strategy focused on a customer's total energy needs.

Creation of Vertically Integrated Energy Companies

Since 1997, eight convergence mergers—either completed or announced—have created relatively large vertically integrated energy companies that own both power generation, transmission, and distribution assets and natural gas assets, which may include a combination of natural gas production, gathering, and processing facilities, pipelines, and local distribution facilities. These new energy companies represent the first significant combinations of electric and gas companies beyond the established electric-gas distribution utilities. Following is a discussion of three of the eight convergence mergers creating integrated energy companies.

Enron's acquisition of Portland General Corporation in 1997 was the first merger of a natural gas company with an electricity company. Enron is an integrated energy company which, through its subsidiaries and affiliates, engages primarily in natural gas transportation and gas marketing. At the time of the merger, Enron had significant investments in intra- and interstate pipelines, and it was one of the largest natural gas purchasers and marketers in the United States. Enron also owns power plants and engages in electricity trading. Portland General Corporation is a holding company for Portland Electric, a vertically integrated electric utility based in Oregon.

From Enron's perspective, the merger with Portland had significant benefits in two areas. First, the merger strengthened Enron's electricity marketing activities in the West by providing a physical presence and better operational understanding of the region. Second, Portland had experience in managing electricity transmission and distribution systems, which supported Enron's plans to expand its retail electricity business. Some industry observers say that this merger paved the way for other convergence mergers because it successfully tested the regulatory approval process with the Federal Energy Regulatory Commission, which is responsible for assessing the effects of mergers on competition and electricity prices.

Also in 1997, Duke Power Company took a major step in redefining and restructuring its business from predominantly an electric utility to a major integrated energy company by merging with PanEnergy Corporation. Duke Power was an IOU with about 17 gigawatts of generating capacity at the time, offering wholesale and retail electricity services in the southeastern United States. Through smaller acquisitions and joint ventures, Duke Power was already on its way to achieving its objectives of becoming an energy company with diversified products and enhancing its marketing and trading operations when the decision was made to merge with PanEnergy. Duke found that the time and effort required to build the company was taking longer than expected. To keep pace with the rapidly changing energy markets, a merger with a large well-established company was needed.

PanEnergy was a holding company with subsidiaries that operated more than 37,500 miles of natural gas pipelines in the Mid-Atlantic, New England, and Midwest States, and it had a successful gas and electricity marketing and trading subsidiary. The merger complemented Duke's energy trading capabilities and gave it the ability to provide a variety of energy-related products. PanEnergy's pipeline business was viewed by Duke as a reliable and steady source of revenue with the potential for revenue growth as the use of gas-fired power plants in the Mid-Atlantic and New England States increases. Duke is clearly positioning itself to take advantage of the increase in natural gas demand in other regions as well. Recently it unveiled plans to build, own, and operate a major interstate natural gas pipeline that will supply energy markets in Florida and Alabama, where the demand for new generating capacity is growing.

More recently, another electric power company announced a merger with a large natural gas company. Dominion Resources Inc., the parent company of Virginia Power, an electric utility, and Dominion Energy, an unregulated power and natural gas producer, announced plans to merge with Consolidated Natural Gas (CNG). CNG is an integrated natural gas company and one of the Nation's largest producers, pipeline operators, distributors, and retail marketers of natural gas. This merger will create one of the largest fully integrated electric and gas companies in the United States. The combined company expects to increase revenue by marketing a complete line of energy products in the

Midwest, Mid-Atlantic, and Northeast States, which are advanced in deregulating electricity markets. The new company plans to build gas-fired merchant plants along CNG's pipelines in the Midwest and the Pennsylvania-New Jersey-Maryland region to meet both peaking and baseload demand. Both companies have retail marketing and sales operations with few overlapping customers. This provides an opportunity to cross-sell electricity to CNG's retail gas customers and natural gas to Dominion's retail electricity customers.

Convergence of Local Electric and Gas Distribution Utilities

Many electric utilities are merging with natural gas distribution companies either to expand the number of retail customers they serve, or to offer additional products to their current retail customers. Since 1997, 11 mergers between electric and gas distribution companies have been completed or are pending completion (Table 7). Many of these mergers have been in the Northeast, where most electric utilities have divested or are in the process of divesting their power generation assets and are seeking to expand their energy delivery business, as discussed in detail in the previous chapter.

Utilities in other regions are following the trend. For example, natural gas distributor Indiana Energy is merging with SigCorp, a combined electric and gas holding company for Southern Indiana Gas & Electric. An executive of Indiana Energy captured the essence of this type of merger when he said, "With this merger our assets will be split evenly between electricity and natural gas distribution. This balances the company's earning potential while positioning it to deliver energy in whatever form our customers need."[26] Many utility executives believe that convergence is being driven by a growing preference among customers for suppliers that can meet all their energy needs and provide additional services to enhance the overall value of the products offered.

[26] Indiana Energy press release, "Indiana Energy and SigCorp Agree to $1.9 Billion Merger," (June 14, 1999).

5. Joint Ventures and Strategic Alliances in the Electric Power Industry

Although they are neither new nor unique to the electric power industry, the use of joint ventures and alliances is increasing as companies struggle to adjust and adapt to the rapidly changing conditions that regulatory restructuring is spreading through the electric power industry. In part, the popularity of corporate alliances arises from the nature and magnitude of the changes that have also fueled a general increase in corporate combinations in the industry. Their popularity also results from the flexibility and innovative nature typical of joint ventures and alliances.

Characteristics of Joint Ventures and Strategic Alliances

While mergers are the most widely recognized corporate combination, utilities are also forming deals or corporate alliances, which are distinctly different from mergers. Corporate alliances can range from general marketing agreements to joint ownership of a specific operation. Two types of corporate alliances are joint ventures and strategic alliances. They share many of the same characteristics, and each is created through the cooperation of two or more companies with a common goal in mind.

For the most part, the terms “alliance” and “strategic alliance” are synonymous. At times, company press releases and trade-press articles use the terms “joint venture,” “alliance,” and “strategic alliance” interchangeably. However, joint ventures can be differentiated from alliances in general. In joint ventures, the cooperating companies usually create a separate operation (or company) that carries out the daily operations of the project, and many develop new products and services or, in turn, acquire other entities on their own. Joint ventures may be open to others through selling of shares following the initial combination. They have become common among nonregulated subsidiaries and affiliates of utilities that have formed companies to market products and services.

In contrast to joint ventures, alliances between companies usually will not involve creating a separate company. A typical alliance in the energy sector involves the advertising and marketing of complimentary products and services of two or more companies.

Joint ventures and strategic alliances are used for many of the same reasons that companies employ mergers, acquisitions, or divestitures. Like participants in mergers and acquisitions, companies participating in joint ventures and strategic alliances seek to achieve the scale of enterprise seen as necessary for success. Joint ventures and strategic alliances are seldom developed in isolation. Rather, they are often part of a larger strategy that may involve a combination of approaches such as a merger, acquisition, restructuring, diversification, concentration on core business, or divestiture. Many companies see a need to establish leverage through a constellation of alliances as a key element to survival. Participants seek to gain economies of scale and knowledge and to increase geographic scope, reach critical mass, diversify the asset base, share development costs, increase operating efficiencies, penetrate new markets, or take advantage of an established brand name or corporate reputation.

Joint ventures and strategic alliances have become more common as the industry moves toward competition. In part, they have become increasingly popular as participants expand beyond the traditional boundaries of the regulated utility and move into less familiar territory. Joint ventures and especially strategic alliances typically have the advantage of ease of withdrawal. They are not only less costly to undertake than a merger, but all parties retain a separate identity outside the agreement. An unsuccessful venture can be dissolved, usually without significant penalty to the participants, whereas an unsuccessful merger, acquisition, or even the quest for an acquisition may leave a company so weakened that it becomes a takeover target, as in the case of PacifiCorp.[27] Centrus is an example of an unsuccessful joint venture. Formed by Cinergy, Florida Progress,

[27] Shortly after its unsuccessful bid to acquire The Energy Group, a large utility in the United Kingdom, PacifiCorp began shedding assets and underwent significant changes in upper management. It is now being acquired by Scottish Power.

and New Century Energies to develop long-distance telephone service, it was canceled when the participants determined that market conditions did not favor the venture. A joint venture may also be concluded through the purchaseof the interest of one partner by another participant, as in the case of Duke Energy/Louis Dreyfus. Duke Energy acquired the 50 percent held by Louis Dreyfus in the venture to market gas and electric energy and services. (Other examples of joint ventures and strategic alliances are described in the inset box.)

Joint Ventures and Strategic Alliances: Three Examples

PECO Energy Company and British Energy Joint Venture

On August 18, 1997, PECO Energy Company (PECO) and British Energy (BE) formed a limited partnership, Amergen. The venture was established to purchase and operate nuclear power plants in the United States. PECO and BE share expenses and costs equally. No startup capital was involved, and expenses are paid as they are incurred. Ownership of assets acquired by Amergen will be evenly divided between the two parents. To comply with provisions of the Atomic Energy Act regarding foreign ownership of nuclear power plants in the United States, PECO will be the owner of record and have responsibility for plant operation and safety.

Amergen is actively pursuing the policy of acquiring nuclear assets and is in the process of purchasing Three Mile Island (TMI) unit 1 from GPU, Inc. The sale price is $100 million—$23 million for the reactor and $77 million for the plant's nuclear fuel. The cost of the fuel is payable over 5 years. Additional payments might be added to the final sale price depending on the actual energy market clearing prices through 2010. The sales agreement includes a power purchase contract with GPU Energy. In addition, Amergen has expressed interest in several other plants, including Connecticut Yankee (eventually acquired by Entergy). At present, in addition to completing the acquisition of TMI, Amergen is also in the process of acquiring two other plants and majority interest in a third. In April 1999, Amergen reached an agreement to purchase the Clinton plant from Illinois Power. In June 1999, Amergen announced that it is in the process of purchasing two plants from Niagara Mohawk and others. Amergen will acquire Nine Mile Point unit 1 (solely owned by Niagara Mohawk) as well as the partial interest held in Nine Mile Point unit 2 held by Niagara Mohawk and two others. Amergen has multi-year power purchase agreements for all three plants.

South Jersey Industries and Conectiv Joint Venture

Millennium Account Services LLC was announced in October 1998 by Conectiv Power Delivery and South Jersey Industries (SJI). Conectiv is the holding company that was created when Delmarva Power & Light Company and Atlantic Energy, Inc. merged on March 1, 1998. The companies are now combined under the name Conectiv. The purpose of the limited partnership is to provide for combined meter reading, with Conectiv and SJI as equal partners in the venture. By the end of 1999, the current meter reading staffs from the partners will be jointly reading meters for the new company. Ultimately, the goal is for Millennium to expand this service into other States in the Mid-Atlantic region. The venture is also seen to have the potential to add additional functions such as billing and customer service as well. The venture required both regulatory and union approval.

Citizens Power LLC and the City of Pasadena Department of Water and Power Strategic Alliance

Citizens Power LLC and the City of Pasadena (California) have established an alliance to enhance the return on generating and transmission assets of the city. Beginning July 1, 1999 and continuing for a period of 5 years, Citizens will trade excess electricity from Pasadena in the open market. In addition, Citizens will also trade electricity to take advantage of arbitrage opportunities on the extensive transmission system extending from the Pacific Northwest to Utah and Arizona, in which Pasadena is a partial owner. Under the agreement, Citizens will have sole responsibility for any losses incurred as a result of its activities, but Pasadena and Citizens will share in profits from the alliance.

Advantages and Disadvantages

The perceived advantages of joint ventures and strategic alliances include cost savings, an end to duplication of services, consolidation of functions, and an increase in total customer base and/or revenues to reach the "critical mass" perceived as necessary for corporate survival as the industry restructures. Although they are subject to much the same review process, neither the financial burden nor the regulatory review process associated with joint ventures and alliances is as great or as costly as those of mergers or acquisitions. Perceived disadvantages, while similar to those in a merger, may well pose a greater problem in some cases. Because the participants retain their separate identities, joint ventures may be more susceptible to failure resulting from a clash of corporate cultures, a lack of clear direction, or the absence of clear lines of responsibility.

Joint ventures and strategic alliances in the electric power industry vary greatly in scope and purpose, but most have objectives that fit into one or more of four broad categories (Table 9): plant investment, energy marketing, purchasing, and energy services. In addition, many include some aspect of trading, risk management, or telecommunications. Although ventures that involve energy services are the most common, no single category dominates the list. In fact, more than one-third have more than one objective.

Table 9. Major Objectives of Joint Ventures and Strategic Alliances, 1996 Through June 1999

Category	Number of Ventures	Percent of Sample[a]
Plant Investment	10	16.7
Energy Marketing . . .	22	36.7
Purchasing	4	6.7
Energy Services[b]	25	41.7
Other[c]	20	33.3

[a]Sixty joint ventures and alliances taking place from 1996 through June 1999 were sampled for this table. The number of ventures totals more than 60 because many ventures have more than one purpose.

[b]Includes: billing, metering, advertising, energy management, energy efficiency, etc.

[c]Includes: risk management, energy trading, telecommunications, etc.

Source: Compiled from information in trade journals, newspapers, and utility Internet websites, 1996 through June 1999.

Factors in the Formation of Joint Ventures and Strategic Alliances

Corporate combinations, whether they entail the formality of a merger or the less structured joining-together of a joint venture or strategic alliance, involve issues that are neither simple nor confined to the question of whether or not to combine. Underlying the rhetoric of press releases, articles in the trade press, and statements to stockholders are a cluster of strategies and reasons for the undertaking. Joint ventures and strategic alliances may be preferred to a merger or acquisition because they do not typically involve the level of investment required for a merger or acquisition. A strategic alliance, because of its looser structure, may also reduce or eliminate the need for a regulatory review process.

Cost Management: Cost control issues are important in all corporate activities, and the desire for cost savings may be the principal reason for the formation of most joint ventures and strategic alliances. Cost savings in a joint venture or alliance may be achieved through the elimination of duplication and the pooling of resources, knowledge, labor, and/or other assets.

Growth: Mergers are often viewed as the means to achieve growth, especially rapid growth, and obtain the benefits from greater economies of scale. However, where funds are lacking, risk is high, and industry direction is uncertain, companies may well opt to form joint ventures rather than merge or acquire others as a means to grow. For example, in the natural gas industry, some local distribution companies (LDCs) are actively branching out, seeking to strengthen their traditional business by expanding into a different line of endeavor in the same geographic area or by seeking an ally in other markets and combining skills to develop new products. One example is the alliance formed by Columbia Energy and Amway, with Amway distributors marketing gas and electricity for Columbia door-to-door. The largest companies can take advantage of their resource base to engage in a number of different strategies at the same time.

Diversification Beyond the Utility Sector: Expansion and diversification into new lines of business or into new territory are endeavors ideally suited to joint ventures and strategic alliances. Joint ventures and strategic alliances may promote growth either outside the traditional scope of activities of a company or outside the industry itself. For example, General Public

Utilities, an electric utility serving the Mid-Atlantic region, created GPU Solar, which is a joint venture with Astro Power Inc. Astro Power manufactures, markets, and sells a range of solar electric products. GPU Solar was formed to pursue the rapidly growing market for grid-connected solar electric power systems.

Energy Services and One-Stop Shopping: Joint ventures and alliances designed to enhance customer service through the marketing of energy, energy services, and other nontraditional services have become popular. The offerings tend to be flexible, giving customers the ability to choose from a varied menu. The goal of such programs may be to hold existing customers, capture new ones, avoid bypass, pool customers, and / or rebundle services. For example, the Allied Utility Network, a joint venture initially consisting of four LDCs but open to other companies, offers energy services to the residential market. At times, such service offerings tend to go well beyond the scope of those services provided by the regulated LDC. For example, Boston Edison and RCN Corporation (a telecommunication services company) established a joint venture to develop a network for one-stop energy services and telecommunications.[28] Similarly, Duke Energy formed a strategic alliance with Nisource (formerly NIPSCO) to market on-site generation at energy-intensive locations.

Brand Recognition: Joint ventures are often developed to take advantage of the existing reputation of a company or to develop a new name with the potential for recognition in a far wider territory, perhaps nationally. Examples of joint ventures with some form of brand identification include both Simple Choice and Enable of KN Energy, Energy Marketplace of SoCal Gas, and Home Vantage of the Allied Utility Network.

Regulatory Approval Process

The need to ensure fairness and to preserve open markets, although most often considered in the context of mergers and acquisitions, also leads to the examination of proposed joint ventures and alliances by agencies at the Federal, State, and sometimes local levels of government. The concerns of the agencies are no different in the case of a merger or a joint venture. Like mergers and acquisitions, strategic alliances and especially joint ventures may be subject to review by the Federal Energy Regulatory Commission (FERC), the Department of Justice (DOJ), the Federal Trade Commission (FTC), the Internal Revenue Service, the Nuclear Regulatory Commission, and State public utility commissions or their equivalent. The various agencies have the power to impose conditions that must be met in order to secure approval. In particular, DOJ and FTC examine proposed joint ventures for possible abuses of market power that could stem from the proposed combination. They have the authority to withhold approval and prevent the combination from taking place.

The oversight function of the various agencies is limited but often overlapping. When examining prospective corporate combinations, the regulators, the various agencies, and, at times, the courts typically focus on the possibility of unfair advantage in pricing, barriers to entry, and other problems resulting from the joint venture. Continued competition between the partners outside the joint operations is of particular concern to regulatory and judicial bodies. Divestiture of some assets may be required as a condition for the venture.

[28] RCN subsequently became a subsidiary of Boston Edison.

6. Divestiture of Generation Assets by Investor-Owned Electric Utilities

Introduction

Previous chapters discussed how investor-owned utility (IOU) mergers and acquisitions are changing the structure of the electric power industry. IOU divestiture of power generation plants is another facet of change in the industry. Divestiture of assets is defined as the sale of assets to another company or the transfer of assets to a nonutility subsidiary.

IOUs are divesting power generation plants at unprecedented levels. Starting in late 1997 through early September 1999, 51 IOUs (32 percent of the 161 IOUs owning generation capacity) have divested or are in the process of divesting 133.0 gigawatts of power generation capacity, representing approximately 17 percent of total U.S. electric utility generation capacity (Table 10). Of the 133.0 gigawatts, 77.0 gigawatts have been sold or are pending completion of the sale, 31.1 gigawatts are up for sale, and 24.9 gigawatts will be transferred by an IOU to its nonutility subsidiary. Some industry observers have estimated that ownership may change for up to 50 percent of total U.S. generation capacity (about 364 gigawatts as of 1998) over the next 10 years. No one can predict with certainty the volume of future divestitures, but more are expected as restructuring of the electric power industry proceeds.

The idea of an electric utility divesting generation assets can be traced back to before November 1996, when the Federal Energy Regulatory Commission (FERC) issued Order 888 requiring electric utilities to allow access to their transmission lines to other electricity suppliers. The FERC believed that access to transmission lines was necessary in order for a competitive power generation market to develop. Some industry participants believed, however, that open access to the transmission system would not be sufficient. When transmission line capacity becomes limited due to high usage, utilities that own the transmission lines will favor power from their own generators over a competitor's generator. Many thought the answer to this potential problem was for the FERC to require utilities that own both power generators and transmission lines to divest either their power generators or their transmission assets.

In Order 888, the FERC took a less intrusive alternative to actual divestiture of generation or transmission assets by requiring "functional unbundling." Functional unbundling is achieved when a company's organizational structure separates operation of and access to the transmission system from power generation.[29] To comply with functional unbundling, electric utilities created an open access transmission tariff, established separate rates for wholesale generation, transmission, and ancillary services, and established an electronic information network that supplies information on the availability of transmission capacity to customers. All IOUs have complied with the FERC's functional unbundling requirements and in some regions electric utilities have formed independent system operator (ISO) companies and turned control (but not ownership) of their transmission assets over to the ISOs. This can be construed as a way of unbundling power generation from transmission.

Why Investor-Owned Electric Utilities Are Divesting Power Generation Assets

Even though all IOUs have functionally unbundled generation from transmission, and some have formed ISOs,[30] divestiture of generation assets continues, brought on by State restructuring initiatives and strategic decisions of electric utilities. Although a utility may have multiple reasons for divesting its power plants, the present high level of divestitures has been

[29] Federal Energy Regulatory Commission, "Order No. 888 Final Rule," 18 CFR Parts 35 and 385 (April 24, 1996).

[30] A map showing ISOs in operation can be found in Energy Information Administration, *Electric Power Annual 1998, Volume I*, DOE/EIA-0348(98)/1 (Washington, DC, April 1999), p. 17.

Table 10. Status of Power Generation Asset Divestitures by Investor-Owned Electric Utilities, as of September 1999

Status Category	Capacity (GW)	Percent of Total	Percent of Total U.S. Generation Capacity
Sold	44.8	34	6
Pending Sale (Buyer Announced)	32.2	24	4
For Sale (No Buyer Announced)	31.1	23	4
Transferred to Nonutility Subsidiary[a]	24.9	19	3
Total	**133.0**	**100**	**17**

[a]Includes generation capacity owned by a holding company that is being transferred from its electric utility subsidiary to its nonutility subsidiary.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through September 1999.

prompted by State restructuring initiatives creating retail competition. State officials view the separation of power generation ownership from power transmission and distribution ownership as a prerequisite for retail competition. Some States have passed laws requiring utilities to divest their power plants. California, Connecticut, Maine, New Hampshire, and Rhode Island are examples of States with laws explicitly requiring utilities to divest their fossil and hydroelectric generation assets and, potentially, any ownership in nuclear power generating assets.

In other States that have passed electricity industry restructuring legislation, the requirements for unbundling are not always clear, and they vary from State to State. The State public utility commission (PUC) may encourage divestiture explicitly as a means for recovering stranded costs or reducing market power. Many times the PUCs are not explicit in their unbundling requirements, leaving it to the utility to propose a method that satisfies the PUC's unbundling objectives and satisfies the strategic and economic objectives of the utility. The utility prepares a company restructuring plan which may include selling its assets or, alternatively, transferring its assets to an unregulated subsidiary company. Negotiation and compromise between the PUC and the utility are part of the process of finalizing the plan. Not all States that have restructured their electricity industry require resident electric utilities to unbundle their assets. Table 11 presents a summary of divestiture requirements by State.

As a business strategy, a few utilities have decided to sell their power plants, indicating that they cannot compete in a competitive power market. For example, General Public Utilities, serving customers in New Jersey and Pennsylvania, recently completed the sale of its fossil-fueled and hydroelectric generating assets, and will focus on running its transmission and distribution systems. Potomac Electric Power Company, serving primarily Maryland and Washington, DC, announced in February 1999 that it will sell its generation business and concentrate on distribution. Both of these companies concluded that at their present level of power generation capacity, they are too small to compete effectively in a competitive power market. Small companies cannot achieve the economies of scale that larger power generation companies achieve, making it difficult for them to compete in the new market place. It is expected that more small electric utilities will either merge with other utilities or sell their power generation assets.

In a few instances, an IOU will divest power generation capacity to mitigate potential market power resulting from a merger. For example, American Electric Power Company and Central and South West Corporation have agreed, as a condition for obtaining approval of their pending merger, to divest 1,604 megawatts of generation capacity in Texas.

Five Census Divisions Accounting for Most Generation Asset Divestitures

Five census divisions—Middle Atlantic, New England, South Atlantic, East North Central, and Pacific Contiguous—account for a total of 121.1 gigawatts of the divested capacity, representing 91 percent of the 133.0 gigawatts of actual and planned divestitures in the United States as of early September 1999 (Figure 8). The majority of divestitures are concentrated in these regions because the States in these regions were among the first in the Nation to promote retail competition. With the

Table 11. Status of State Restructuring Provisions on Divestiture of Power Generation Assets, as of September 1999

State	Restructuring Legislation	Requirements for Divestiture of Generation Assets
Arizona	HB 2663 passed 5/98	HB 2663 allows Arizona Corporation Commission (ACC) to issue rules on divestiture. The ACC ruled in 4/99 that divestiture is not required, but is given as one of the options utilities may use for recovery of stranded costs. Tucson Electric Power to transfer its generation to an unregulated affiliate.
Arkansas	SB 791 passed 4/99	SB 791 gave the Public Utility Commission (PUC) the authority to require divestiture to alleviate market power. Otherwise divestiture is not required. PUC may require transfer or divestiture of generation if market power is excessive.
California	AB 1890 passed 9/96	AB 1890 requires the IOUs to divest 50 percent of their generation. PG&E to divest at least 50 percent of generation. S Cal Ed to divest at least 50 percent of generation. SDG&E to divest fossil generation as condition of Enova-Pacific Enterprises merger.
Connecticut	HB 5005 passed 4/98	HB 5005 requires utilities to divest all generation, including nuclear. Connecticut is the only State requiring complete divestiture of nuclear generators. Law requires utilities to divest generation as a condition of stranded cost recovery.
Delaware	HB 10 passed 3/99	HB 10 allows the Public Service Commission (PSC) to decide if divestiture is needed to alleviate market power "in extreme situations and as a last resort." Stranded cost recovery is not an issue for the IOU in Delaware. Delaware Cooperative's stranded cost recovery will be addressed by the PSC.
Illinois	HB 362 passed 12/97	HB 362 does not require divestiture. Commonwealth Edison to voluntarily divest some of its generation capacity.
Maine	LD 1804 passed 5/97	LD 1804 requires divestiture of all generation and related assets except nuclear, QF contracts, foreign assets, and those deemed necessary by the PUC to provide efficient transmission and distribution services. Law requires divestiture of generation assets by 3/1/2000.
Maryland	HB 703 passed 4/99	HB 703 forbids mandated divestiture. However, Potomac Electric Power Co. is selling all its generation assets.
Massachusetts	HB 5117 passed 11/97	HB 5117 does not require divestiture, but strongly encourages divestiture for utilities seeking to recover stranded costs. New England Electric System to divest all generation in return for 100 percent stranded cost recovery. Boston Edison to divest all non-nuclear generation.
Michigan	No legislation passed. Public Utility Commission issued restructuring order.	The PSC issued an order for restructuring that does not require divestiture. A recent Supreme Court order has ruled the PSC does not have the authority to order restructuring. However, both IOUs in Michigan are voluntarily restructuring. Consumers Power and Detroit Edison have had restructuring plans approved. Consumer Energy to reduce its generation assets by 15 percent by 2002.
Montana	SB 390 passed 4/97	SB 390 does not require divestiture; however, Montana Power is selling its generation assets.
Nevada	AB 366 passed 7/97	AB 366 and SB 438 do not require divestiture, but FERC requires divestiture as a condition for the merger between Sierra Power and Nevada Power.
New Hampshire	HB 1392 passed 5/96	HB 1392 requires divestiture. Law requires full divestiture, but it is being challenged in court.
New Jersey	A10 and S5 passed 2/99	Laws A10 and S5 leave divestiture and the issue of stranded cost recovery up to the Board of Public Utilities which may require divestiture.
New Mexico	SB 428 passed 4/99	SB 428 allows utilities to transfer ownership of generation to affiliate companies. Utilities may transfer ownership of generation assets to a separate affiliate.

Table 11. Status of State Restructuring Provisions on Divestiture of Power Generation Assets (continued)

State	Restructuring Legislation	Requirements for Divestiture of Generation Assets
New York	No legislation passed. Public Utility Commission has approved utilities' restructuring plans.	No legislation was required for the Public Service Commission to approve restructuring plans of each utility. The utilities are using divestiture to reduce stranded costs. Consolidated Edison to divest at least half of its NYC generation by end of 2002. New York State Electric & Gas to divest its non-nuclear generation by 8/99. Orange & Rockland to divest all generation and has financial incentives to do so by 5/1/99. Central Hudson Gas & Electric to divest non-nuclear generation by 6/30/01. Rochester Gas & Electric given financial incentives to divest all generation by 2001.
Ohio	SB 3 passed 6/99	SB 3 does not require divestiture.
Oklahoma	SB 500 passed 4/97	SB 500 does not require divestiture.
Oregon	SB 1149 passed 4/99	SB 1149 does not require divestiture.
Pennsylvania	HB 1509 passed 12/96	HB 1509 does not require divestiture. Some Pennsylvania utilities are selling generation assets to reduce stranded costs and/or restructure their companies into "wire" companies by getting out of the generation side of the business. Duquesne Light to divest generation. Allegheny Energy to transfer generation to affiliated generation company or divest.
Rhode Island	HB 8124 passed 8/96	HB 8124 requires utilities to divest their generation, but allows these assets to be transferred into separate affiliate companies.
Texas	SB 7 passed 6/99	SB 7, while not requiring divestiture, does state that utilities must unbundle into three separate categories (generation, distribution and transmission, and retail electric provider functions) using separate companies or affiliate companies. Also, utilities will be limited to owning and controlling not more than 20 percent of installed generation capacity in their reliability region (ERCOT), a rule which could require divestiture of some generation assets.
Vermont	No legislation passed. Public Service Commission ruled to restructure the industry.	The Public Service Commission (PSC) ruled to restructure the industry, but the implementation of any restructuring requires legislation. No legislation has passed or is expected in the near future. However, Central Vermont Public Service and Green Mountain Power filed a joint divestiture plan with the PSC.
Virginia	SB 1269 passed Senate 2/99	SB 1269 does not require divestiture. Dominion Resources (parent company of Virginia Power) will create a new subsidiary, Dominion Generation, which will own and operate all its power generation plants.

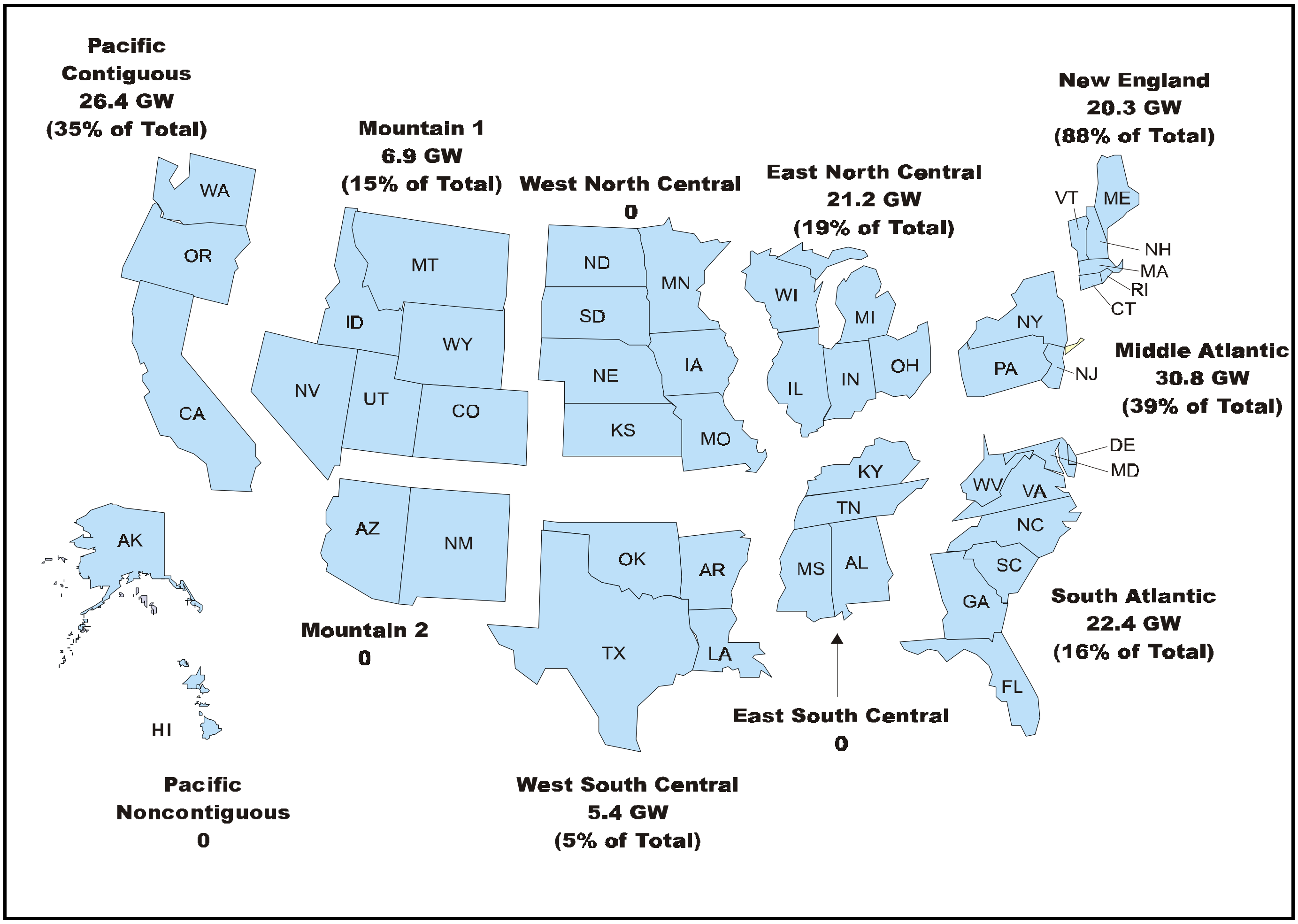
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from a review of State legislation, Public Utility Commission Orders, and press releases available on Internet websites.

exception of States in the South Atlantic Division, most of the States in the other four divisions passed legislation in 1996 or 1997 restructuring the electricity industry, and they have had over 2 years to implement their restructuring programs.

IOUs in New England have just about completed divesting their power plants; approximately 20.3 gigawatts have been sold, representing about 88 percent of the region's generating capacity. Capacity in the region that has not been divested is owned by nonutility related companies or municipal or Federal Government power plants. IOUs in the Middle Atlantic region, mainly New York and Pennsylvania, have divested or are in the process of divesting almost 31 gigawatts, accounting for approximately 39 percent of the region's generating capacity. IOUs in California have divested slightly over 26 gigawatts, representing about 35 percent of the generating capacity in the Pacific Contiguous region.

Dominion Resources (parent company of Virginia Power) tops the list of power generation divestitures (Table 12). Recently, the company announced that all Virginia Power's generation capacity will be transferred to a new nonutility subsidiary, Dominion Generation. Unicom (formerly Commonwealth Edison), serving the

Figure 8. Investor-Owned Electric Utility Generation Capacity Divested or to be Divested by Census Division, as of September 1999



Note: Nationally, approximately 17 percent of total power generation capacity has been divested or will be divested.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through September 1999.

Midwest region, has sold or plans to sell almost 50 percent of its generating capacity, consisting of a mix of coal- and gas-fired generating plants. Unicom will not exit the generation business entirely, keeping its large nuclear power fleet of over 12 gigawatts of capacity intact. Unicom stated that it will use some of the proceeds from the sales to reduce the operating costs of its nuclear plants to make them more competitive with other power plants.

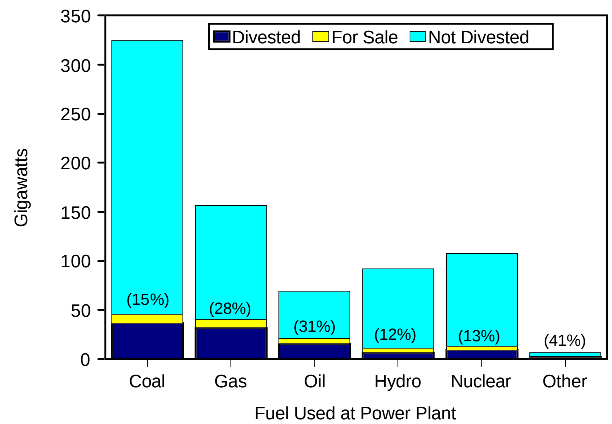
Two California utilities, Pacific Gas & Electric and Southern California Edison, were required to divest 50 percent of their fossil-fueled power plants. Combined, they have divested about 70 percent of their generation capacity. Individually, they rank as third and fourth highest, respectively, in total capacity divested in the United States. Interestingly, Pacific Gas & Electric Corporation sold its generating capacity in California, but through its affiliated independent power producer, Pacific Gas & Electric Generating Company (a wholly-owned subsidiary of Pacific Gas & Electric Corporation), it is one of the leading purchasers of generating assets in other regions. Pacific Gas & Electric Generating Co. purchased most, if not all, of the generating capacity sold by New England Electric System in early 1998. This is an example of a trend in the power generation business where an electric utility holding company expands its power generation capability in regions outside of its regulated utility's franchise area. Many electric utility holding companies are growing in this way.

Table 12. List of the 10 Largest Investor-Owned Utility Companies Divesting Generation Assets, as of September 1999

Utility	Capacity Divested (Gigawatts)
Dominion Resources (Virginia Power)	13.3
Unicom (Formerly Commonwealth Edison)	11.0
Pacific Gas & Electric Corp.	10.8
Southern California Edison	10.4
Consolidated Edison	7.0
General Public Utilities System	6.9
Potomac Electric Power Co.	6.0
Niagara Mohawk Power	5.3
Illinois Power	4.7
Duquesne Light	4.4
Total Capacity	**79.8**

Sources: Capacity divested data were compiled from trade journals and from utility and State public utility commission websites.

Figure 9. Power Generation Divestitures of Investor-Owned Electric Utilities by Fuel Type, as of September 1999



Note: Numbers in parentheses indicate percent of fuel type divested.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

Types of Generation Assets Divested

Coal- and gas-fired plants top the list of divested power plants (Figure 9). About 46 gigawatts of coal-fired capacity (15 percent of total coal-fired capacity) and 41 gigawatts of gas-fired capacity (28 percent of total gas-fired capacity) have been divested or are up for sale. There are three reasons fossil fuel plants top the list. First, coal- and gas-fired power plants combined account for approximately 64 percent of U.S. electricity generation capacity, and it is reasonable that divestiture of those plants would follow a similar distribution. Second, because of their relatively low production costs, coal-fired plants are a desirable investment, assuming they are well maintained. Production costs of coal-fired plants average 1.8 cents per kilowatthour, making them among the lowest cost plants operating today. In addition, coal prices are expected to continue falling, which should bring production costs down even further. On the downside, however, coal-fired plants can be controversial because of SO_2, CO_2, and NO_x emissions.

The majority of gas-fired plants divested were old steam turbine plants that have perhaps a less promising future than coal-fired plants. Even though their production costs have declined over the past few years, existing gas-fired steam turbine plants remain more expensive than coal plants and other new power plant technologies. However, because existing gas plants have established access to gas supplies, it is reasonable to assume that, over time, many of them will be replaced by more efficient gas combined-cycle plants, thus making the sites on which the plants are located valuable in themselves. The use of natural gas combined-cycle plants is expected to increase over the coming years.

Third, many States that have opened the industry to competition have encouraged the divestiture of fossil-fuel plants first, while delaying recommendations for divestiture of other plants (especially nuclear power, which in 1998 was the second largest power source for generation in the United States). For example, California initially requested Pacific Gas and Electric and Southern California Edison to divest at least 50 percent of their fossil-fueled plants; but both companies will maintain ownership, at least over the intermediate future, of their nuclear power capacity. The New York Public Service Commission insisted that utilities divest fossil and hydroelectric plants to help ensure fair competition but delayed any decision covering nuclear power until further study was completed.

Delaying divestiture of nuclear power plants is justified, in part, because of the more difficult and complex issues associated with nuclear generators compared with other power plants. First of all, because nuclear power has stringent safety requirements, the capability of new owners to operate nuclear power plants must be evaluated to determine that they will continue to meet the safety requirements. The Nuclear Regulatory Commission has this responsibility. Further, nuclear power plant owners must maintain a decommissioning fund to cover the expenses of safely shutting down the plants when they are retired, which has been shown to be quite expensive. New owners must demonstrate their ability to maintain the funds. The time and resources it takes to buy a nuclear power plant may also distract from the desire of potential purchasers. Estimates range from 12 to 18 months to obtain regulatory approval to transfer ownership of a nuclear power plant.

Nevertheless, a few nuclear power plants have been divested. Currently, 9.1 gigawatts of nuclear power generating capacity have been sold, and another 4.2 gigawatts are up for sale. Because nuclear power plants are, in many cases, jointly owned, some of these sales involve only a portion of the plant. For example, Niagara Mohawk Power Company, in its effort to divest all generating assets, announced early this year its intention to sell Nine Mile Point unit 1, which it owns outright, and a 41-percent share of Nine Mile Point unit 2. Also, Virginia Power, which owns 3.2 gigawatts of nuclear power capacity, will transfer ownership of its plants to Dominion Generation, a nonutility subsidiary of Dominion Resources.

Three nuclear power plants, which are not jointly owned, will change ownership entirely. In July 1998, General Public Utilities announced the sale of Three Mile Island unit 1 to AmerGen Energy, Inc.—a joint venture of the Philadelphia-based utility company, PECO Energy, and British Energy PLC. When this sale is completed, which is expected in 1999, it will be the first time a nuclear power plant in the United States has changed hands. Closely following this transaction, Boston Edison announced in November 1998 the sale of its Pilgrim nuclear power plant in Massachusetts to Entergy Nuclear Generating Company. This sale was the first completed competitive bid for a nuclear plant in the United States.

Recently, Illinois Power announced that it was selling its Clinton nuclear power plant to AmerGen Energy. The sale of the Clinton plant supports the notion that single-unit nuclear operators (i.e., operators that own only one nuclear plant, such as Illinois Power) will eventually sell their nuclear assets to larger companies specializing in owning and operating nuclear power plants. AmerGen Energy and Entergy Nuclear are two companies that have expressed an interest in expanding their nuclear power business. One way to expand is by purchasing nuclear plants; another way is by merging with a company that owns nuclear power capacity.

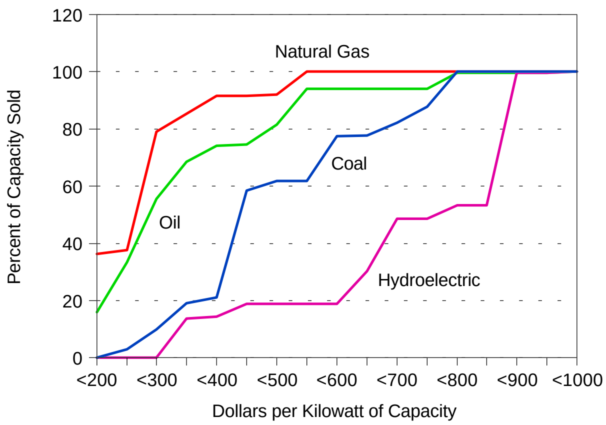
Wide Variation in Selling Prices of Generation Assets

The selling price (or purchase price) of generating capacity is determined by a variety of factors, including the plant's age and condition, fuel, and location, among others.[31] The projected electricity demand in regions surrounding the plant and other market factors also come into play. Thus, it is not surprising to see a wide variation in the selling price of power plants (Figure 10). Power plants that are being transferred from an IOU to a nonutility subsidiary at book value are not included in this analysis.

About 80 percent of the gas-fired capacity that has been divested has been sold for less than $300 per kilowatt of capacity. In contrast, coal-fired plants were significantly more expensive on average. Only about 10 percent of the coal-fired capacity divested has been sold at $300 per kilowatt or less. From the standpoint of operating costs, the price differentials are reasonable. The relatively low price for gas compared to coal is consistent with the fact that the steam turbine gas plants have on average a

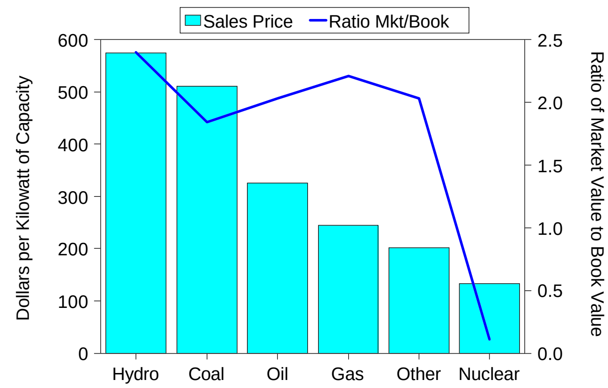
[31] The reported selling price of generation assets may not, in some instances, represent the real value of the assets. Sales often include side conditions which are important determinants of the price. Real estate, inventories, licences, and zoning permits are some of the ancillary items involved in plant sales which have a bearing on price. Nuclear plant sales often contain side conditions relating to the disposition of the decommissioning fund and impact of the sale on the local tax base which may have financial implications for the seller far greater than the actual price of the plant. For most sales, the plants are bundled into one package, and the selling price is reported for the total package. To estimated a selling price by type of fuel, the aggregate selling price is proportioned according to the capacity of each fuel type. This technique may distort comparisons, tending to smooth out the differences that would have appeared had each plant been sold individually. Indeed, one of the reasons for bundling plants is to pair low-value plants with high-value plants to improve the chances of selling the low-value plant. The general result is that the value of hydroelectric plants, and to a lesser extent coal plants, are understated. Nuclear plants have generally been sold separately so they have not been subject to this bundling distortion. A general caveat to the interpretation of prices is that in an auction, the bidder with the most optimistic view of the assets will win the auction. If you assume that the submitted bids are randomly distributed around the "true" value of the asset, the result will be prices that regularly overstate the asset's value.

Figure 10. Percent of Capacity Sold by Price Range and Fuel Type, as of September 1999



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

Figure 11. Estimated Average Selling Price of Power Generation Capacity by Fuel Type, as of September 1999



Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

higher production cost than coal plants; this probably lowers the value and selling price of gas plants. Hydroelectric plants have sold at a relatively high price on average; approximately 50 percent of the capacity divested has been sold for $750 per kilowatt or more. This is not surprising because hydroelectric plants have relatively low operating costs and can effectively compete in a competitive energy market with plants using other fuels. Also, they can be brought online rapidly, which is valuable when the demand for electricity is higher than normal.

Although there is a large variation in selling prices by type of fuel, IOUs have received relatively high prices for their power plants across all fuels, except nuclear power. Most of the generating capacity has sold for more than book value, ranging from 1.5 to over 2.5 times book value (Figure 11). Book value is the original cost of the plant minus accumulated depreciation.[32] These relatively high prices indicate a strong market for existing generating capacity, and some of the buyers believe that they can recoup their investments in a competitive market. In some instances, buyers may be bidding up the prices of existing plants because they are interested in expanding generation capacity at the site, and they can bypass the difficult and time-consuming job of locating and obtaining approval of new sites. For example, Sithe Energies, a foreign-owned independent power producer, recently purchased Boston Edison's non-nuclear plants. Sithe indicated that it plans to build gas-fired generators on two of the purchased sites.

The selling prices of power plants might be higher than expected in part because of the selling method. Most of the plants were sold through competitive auctions which, if properly designed, can produce higher prices and greater revenues for the seller than would strictly negotiated sales.

Nuclear facilities are the only plants that have not sold at high prices. The Pilgrim and Three Mile Island nuclear plants recently sold for significantly less than their book values. The uncertainty of the future of nuclear power, and the additional safety and regulatory requirements compared with other fuels, contribute to the relatively low selling prices. Also, weak demand, manifested by relatively few buyers interested in acquiring nuclear assets, may contribute to low selling prices.

[32] Book values suffer similar problems as selling prices. They are based on values reported in the press or gleaned from 10-K reports for the seller, and they are only rarely available on a plant-by-plant basis. For sales involving plants fired by several fuel types (i.e. primary natural gas, and secondary oil), the book value was proportioned according to capacity for each fuel type. This may tend to overstate the value of older plants. Also, book values may be distorted by the differing real estate and inventory values associated with each sale. A further problem is the time dependency of book values. The data used here try to use a book value as close to the closing date of the sale as is possible.

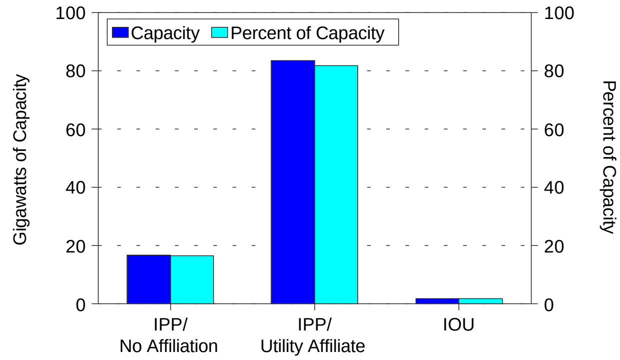
Buyers of Power Generation Assets

Virtually all the generation capacity that has been divested to date has been acquired by companies classified as independent power producers (IPPs). IPPs are independent from regulated electric utilities; they do not own bulk power transmission or distribution lines, and essentially they are unregulated companies that produce and sell power in wholesale markets or directly to wholesale customers under bilateral agreements. Of the 101.9 gigawatts of divested capacity for which a new owner has been announced, 100.2 gigawatts will be acquired by IPPs. The preponderance of independent companies is expected because the central idea of divestiture is to unbundle an electric utility's ownership of power generation from its ownership of transmission and distribution.

The interesting point is that most of the divested capacity is being acquired by nonutility subsidiaries of utility holding companies (Figure 12), referred to as utility-affiliated IPPs. Of the 101.9 gigawatts of divested capacity, 83.4 gigawatts (82 percent) has been acquired by IPP utility affiliates. These acquisitions allow electric utility holding companies to expand their power generation business outside of the traditional service areas of their regulated utility subsidiaries. For example, Southern Energy, an IPP owned by the Southern Company, recently acquired a total of 6.6 gigawatts of generation capacity in California, New England, and Indiana. Southern Company owns five electric utility subsidiaries in the Southeast region of the United States, and it is one of the largest electric utility holding companies and producers of electricity in the United States.

Although IPPs have been producing power on a small scale for some time, recent acquisitions of generation capacity demonstrate that IPPs are becoming major players in the U.S. power generation business. The top 10 companies, all of which are IPPs, have acquired almost 68 gigawatts of divested generation capacity, representing about 67 percent of the divested capacity for which new owners have been announced (Table 13). Dominion Generation, the newly created IPP affiliate of Dominion Resources, leads the list and will own and operate all of Virginia Power's generation capacity when the transfer is completed. Closely following is Edison Mission Energy, a subsidiary of Edison International Corporation (which also owns Southern California Edison), with an acquisition of 11.3 gigawatts. Edison Mission Energy purchased generation assets from Unicom and is now a major power generation company in the Midwest. The data suggest that IPPs as a whole

Figure 12. Buyers of Divested Power Generation Capacity by Type of Buyer, as of September 1999



IPP = Independent Power Producer.
IOU = Investor-Owned Electric Utility.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels. Compiled from information in trade journals, newspapers, and Internet websites, 1998 through early September 1999.

are not only growing in terms of owning more generation capacity, but with these recent acquisitions, ownership of capacity within the IPP sector is becoming more concentrated.

Selling Generation Assets and the Approval Process

How power plants are sold is important to the owner and potential buyers. The procedure should ensure fairness to all interested buyers and ensure that the utility gets a fair market value. The most popular divestiture method is the auction. The advantages of auctions are that they have been used successfully for many years to sell products, they can be easily understood and monitored, and they can produce greater revenues than other methods, if designed properly.

Many of the IOUs divesting assets have used a two-stage auction process. In the first stage, the utility advertises the sale of the plant and bidders submit notifications of interest back to the utility. Advertising the sale of the plant can be accomplished in many ways. One way is to develop a potential buyers list and send each one a notification that a power plant is for sale. In the second stage, the utility selects a "shortlist" of buyers. Short-listed bidders conduct due diligence and submit their final bids. Sometimes post-bid negotiations are conducted, but they have the tendency to

Table 13. List of the 10 Largest Companies Acquiring Generation Assets, as of September 1999

Company Name	Type of Company	Capacity Purchased (Gigawatts)
Dominion Generation	IPP/Utility Affiliate	13.3
Edison Mission Energy	IPP/Utility Affiliate	11.3
NRG Energy	IPP/Utility Affiliate	6.9
Southern Energy	IPP/Utility Affiliate	6.6
Sithe Energies	IPP/No Affiliation	6.3
AES Corp.	IPP/No Affiliation	6.1
Orion Power Holding	IPP/Utility Affiliate	5.4
Allegheny Energy Generation Co.	IPP/Utility Affiliate	4.1
Pacific Gas & Electric Generating Co. (formerly US Generating Co.).	IPP/Utility Affiliate	4.1
Illinova Generation Co.	IPP/Utility Affiliate	3.8
Total Capacity		**67.9**

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels; capacity purchased data compiled from trade journals and from utility and State public utility commission websites.

reduce the bid price because the bidder, knowing that negotiations will be conducted, can change the original bid price.

When the divestiture involves many plants, packaging of the plants is important. Packaging refers to the group of assets that will be sold at one auction. In many cases, bidders cannot submit a bid for just some of the assets, but must bid on all the assets in the package. Thus, it is important to combine assets in a way that will interest potential buyers.

Appendix B contains case studies describing how three utilities went about selling their power plants and some key issues they faced. The cases were selected to represent different States and conditions under which utilities are divesting their power plants.

All power plant sales must be approved by the PUC of the affected States. The PUC examines the sale's impact on the utility's customers, the environment, and other public interests, and resolves any conflicts which arise. Ideally, contentious issues are resolved during the planning stage.

With the exception of hydroelectric power plants, the Federal Government has only a small role in IOU asset divestitures. The FERC's position is that generation assets are not under its jurisdiction and its approval is not required unless the sale includes transmission assets along with generation assets. That position is being challenged, however, by the American Public Power Association (APPA). The APPA claims that Section 203 of the Federal Power Act gives jurisdiction to the FERC, and has filed a petition requesting the FERC to assert its review authority over the sale of generation assets. The APPA's petition is still open.

7. Summary and Conclusions

Deregulation of the electric power industry is forcing investor-owned utilities (IOUs), who once were regulated and more or less insulated from competitive pressures, to formulate strategies that will help them to compete in the changing industry. Many times the strategy is a merger, acquisition, or some other form of a corporate combination.

Recent mergers between IOU holding companies have created large vertically integrated regional electric utilities and, with 16 mergers now pending, more will be created. One affect of these mergers is that ownership of power generation capacity is becoming more concentrated. The 20 largest IOUs now own about 60 percent of the total investor-owned generation capacity. By 2000, the top 20 IOUs will own an estimated 73 percent.

Another affect is that mergers can result in operating efficiencies for the combined companies which translate into cost savings. Two case studies of mergers occurring a few years ago concluded that significant cost savings were achieved. However, cost savings do not necessarily translate into reduced rates to the customer. One of the studies showed lower rates after the merger than before the merger, while the other study showed no appreciable change in rates after the merger.

For the first time in the industry's history, a foreign company will acquire ownership of a U.S. electric utility. Presently, two acquisitions by foreign companies are pending approval. More may follow as some growth-minded foreign energy companies believe that the deregulated electricity industry is a good investment opportunity.

Independent power producers (IPPs) are a growing segment in the industry. Again, for the first time in the industry's history, an IPP has acquired an IOU, and another IPP acquisition of an electric utility is pending. As deregulation continues, more of the Nation's power generation capacity may be purchased by large independent power generation companies.

Induced by State government restructuring initiatives and emergence of competition, many IOUs have divested their power generation assets and will focus on operating their transmission and distribution business. From 1998 through September 1999, IOUs have either divested or are in the process of divesting approximately 133.0 gigawatts of power generation capacity. Most, if not all, of this capacity has been acquired by IPPs, furthering the growth of the IPP segment of the industry.

Divestiture has some tangible benefits to IOUs and potentially to electricity customers. In many cases the divested assets were sold substantially above book value. The IOU will use the proceeds from the sales to reduce its stranded costs, which in turn may help to lower electricity rates to customers. Some of the power plant buyers have indicated they will upgrade the power plants, which should improve operation of the plant and, in the long run, lower costs.

Over the past few years, IOUs have increasingly merged with natural gas production and gas pipeline companies, creating vertically integrated energy companies. These mergers are motivated primarily by the growth in gas-fired power plants and the opportunity to become a major fuel supplier for these power plants. Combined electricity and natural gas marketing and diversification of products and services are also reasons for these mergers.

Increasingly, IOUs are forming joint ventures and alliances to meet a specific requirement or to explore new business opportunities. Cost sharing and risk sharing are two reasons why these types of combinations are popular. Typical joint ventures include plant investment or forming a company to provide energy services such as billing, metering, or advertising.

Since passage of the Energy Policy Act of 1992, considered by some the beginning of competition in the industry, the types of corporate combinations outlined in this report have accelerated. Not only do these combinations strengthen a company's ability to compete, in the aggregate they have had a significant effect on the overall corporate structure of the industry.

Appendix A

The Public Utility Holding Company Act of 1935

Appendix A

The Public Utility Holding Company Act of 1935

Introduction

As mentioned in Chapter 1, the Public Utility Holding Company Act of 1935 (PUHCA) is being targeted for immediate repeal by some groups because of its restrictions regarding utility mergers and acquisitions which might save money for customers and enhance profits for shareholders. Other groups firmly believe that, while its provisions are becoming obsolete, PUHCA cannot be repealed until comprehensive electric utility industry restructuring legislation is instituted. Mergers would grow if the law was repealed outright and, since mergers reduce the number of competitors, competition could be meaningless. This appendix explains the effect the law is having today on corporate combinations in the Nation's electric power industry and takes a look at the advantages and disadvantages of the law's regulations in light of the current move towards competition. A background section which explains the basics about why PUHCA was promulgated 65 years ago is provided in order to help the reader fully understand the current controversy surrounding the law.[33]

Background

The Public Utility Holding Company Act (PUHCA), enacted in 1935, was aimed at breaking up the unconstrained and excessively large trusts that then controlled the Nation's electric and gas distribution networks. They were accused of many abuses, including "control of an entire system by means of a small investment at the top of a pyramid of companies, sale of services to subsidiaries at excessive prices, buying and selling properties within the system at unreasonable prices, intra-system loans at unfair terms, and the wild bidding war to buy operating companies."[34] The Act was passed at a time when financial pyramid schemes were extensive. These schemes allowed operating utilities in many areas of the country to come under the control of a small number of holding companies, which were in turn owned by other holding companies. These pyramids were sometimes 10 layers thick (see box on next page).

"Some holding companies were solid operations run for no other purpose than to coordinate and make efficient the operation of the subsidiary companies. But the holding company movement became a craze because of the promotional profits to be made. The holding companies were condemned and fell because of the excesses committed. The present structure of the electric utility industry is the direct result of legislation designed to destroy the holding company that did not have an operating rationale for its existence. As promoters saw the huge profits to be gained from the holding company business, they began to bid against each other to buy operating properties to put into the holding companies. Sometimes the promoters had to resort to odd measures to make things look good. One could, for instance, combine electric and ice properties, hiding the fact that most of the earnings were coming from the competitive, unsafe, and dwindling ice business. A good promoter could put together a combination of companies, sell preferred stock and bonds to the public to pay for the properties, take 10 percent or more as a commission, and keep the bulk (or all) of the voting common stock of the holding company, thereby remaining in control without having paid a cent into the business."[35]

Before PUHCA, almost half of all electricity generated in the United States was controlled by three huge holding companies, and more than 100 other holding companies

[33] For a very detailed look at PUHCA, refer to *The Public Utility Holding Company Act of 1935: 1935-1992* (DOE/EIA-0563). To receive a hard copy, contact EIA's National Energy Information Center by phone at (202) 586-8800 or by E:mail at infoctr@eia.doe.gov. It can also be viewed and downloaded from EIA's World Wide Web Site at: http://www.eia.doe.gov.

[34] L. S. Hyman, *America's Electric Utilities: Past, Present and Future,* Fifth Edition (Arlington, VA: Public Utilities Reports, Inc., 1994), p. 111.

[35] *Ibid*., p. 101.

The following excerpt from *America's Electric Utilities: Past, Present and Future* demonstrates the complexities that resulted from the leveraging that took place within the holding company systems:

The Insull[a] interests (which operated in 32 states and owned electric companies, textile mills, ice houses, a paper mill, and a hotel) controlled 69 percent of the stock of Corporation Securities and 64 percent of the stock of Insull Utility Investments. Those two companies together owned 28 percent of the voting stock of Middle West Utilities. Middle West Utilities owned eight holding companies, five investment companies, two service companies, two securities companies, and 14 operating companies. It also owned 99 percent of the voting stock of National Electric Power. National, in turn, owned one holding company, one service company, one paper mill, and two operating companies. It also owned 93 percent of the voting stock of National Public Service. National Public Service owned three building companies, three miscellaneous firms, and four operating utilities. It also owned 100 percent of the voting stock of Seaboard Public Service. Seaboard Public Service owned the voting stock of five utility operating companies and one ice company. The utilities, in turn, owned eighteen subsidiaries.[b]

[a]Samuel Insull worked for Thomas Edison and later became the vice-president of Edison General Electric Company. In 1887, Insull established the Chicago Edison Company, and in 1897 Commonwealth Electric was formed. In 1907, Insull consolidated Chicago Edison and Commonwealth Electric to form Commonwealth Edison Company.

[b]L. S. Hyman, *America's Electric Utilities: Past, Present and Future, Fifth Edition* (Arlington, VA: Public Utilities Reports, Inc., 1994), p. 102.

existed.[36] The size and complexity of these huge trusts made industry regulation and oversight control by the States impossible. After the collapse of several large holding companies, the Federal Trade Commission (FTC) conducted an investigation after which it criticized the many abuses that tended to raise the cost of electricity to consumers. The Securities and Exchange Commission (SEC) also investigated and "publicly charged that the holding companies had been guilty of stock watering and capital inflation, manipulation of subsidies, and improper accounting practices. The general counsel of the FTC went further, claiming that [w]ords such as fraud, deceit, misrepresentation, dishonesty, breach of trust, and oppression are the only suitable terms to apply."[37]

Under PUHCA, the SEC was charged with the administration of the Act and the regulation of the holding companies. One of the most important features of the Act was that the SEC was given the power to break up the massive interstate holding companies by requiring them to divest their holdings until each became a single consolidated system serving a circumscribed geographic area. Another feature of the law permitted holding companies to engage only in business that was essential and appropriate for the operation of a single integrated utility. The law contained a provision that all holding companies had to register with the SEC, which was authorized to supervise and regulate the holding company system. Through the registration process, the SEC decided whether the holding company would need to be regulated under or exempted from the requirements of the Act. The SEC also was charged with regulating the issuance and acquisition of securities by holding companies. Strict limitations on intrasystem transactions and political activities were also imposed.[38]

The holding companies at first resisted compliance, and some challenged the constitutionality of the Act, but the Supreme Court upheld PUHCA's legality. By 1947, virtually all holding companies had undergone some type of simplification or integration, and by 1950 the utility reorganizations were virtually complete.[39]

PUHCA in the 1990s

In essence, the restrictions facing today's utility holding companies regarding acquisitions fall into two categories–geographic and functional. Geographic restrictions require a holding company which seeks to acquire utilities that operate in non-contiguous States to "register" with the SEC. Functional restrictions do not allow a

[36] The Securities and Exchange Commission actually noted 142 registered holding companies in 1939. Securities and Exchange Commission, *Fifth Annual Report of the Securities and Exchange Commission, Fiscal Year Ended June 30, 1939* (Washington, DC, 1940), pp. 1 and 43.

[37] T. J. Brennan et al., *A Shock to the System: Restructuring America's Electricity Industry* (Resources for the Future: Washington, DC, July 1996), p. 160.

[38] For a more extensive and detailed discussion of PUHCA, see Energy Information Administration, *The Public Utility Holding Company Act of 1935: 1935-1992*, DOE/EIA-0563 (Washington, DC, January 1993), pp. 39-53.

[39] J. Seligman, *The Transformation of Wall Street and The History of the Securities and Exchange Commission in Modern Corporate Finance* (Boston, MA: Houghton, Mifflin Company, 1982), p. 134.

registered holding company to engage in businesses that are not functionally related to their core utility business. "Thus, while an 'exempt' holding company (e.g., one whose utility operations are predominantly in a single State) can diversify into virtually any business line (within bounds established by State law),[40] a registered holding company must only engage in utility-related businesses that perform functions primarily for the benefit of affiliated utility companies."[41]

A holding company is a company that confines its activities to owning stock in, and supervising management of, other companies. The SEC, as administrator of PUHCA, defines a utility holding company as a company which directly or indirectly owns, controls, or holds 10 percent or more of the outstanding voting securities of a public utility company. "Where merging utilities decide to retain their existing operating company structure, the resulting combination must meet the requirements of PUHCA. An investor is generally allowed to take 'one free bite' at the electric utility industry by acquiring less than 10 percent of the voting securities of a single public utility company. However, under the so-called 'two bite' restriction imposed under Section 9(a)(2) of the Act, an investor generally cannot acquire more than a 5 percent voting interest (i.e., become an 'affiliate') in two or more different electric utility companies without obtaining the prior approval of the SEC. The SEC has taken the position that the acquisition of 5 percent or more of the voting securities of a public utility holding company with two or more utility subsidiaries also requires SEC approval under Section 9(a)(2), since this involves the indirect acquisition of 5 percent or more of the securities of two utilities. Even holding companies that are exempt from registration and the other operative provisions of the Act are subject to the 'two bite' restriction."[42]

"It is important to remember that the restrictions contained in PUHCA apply to only those companies that seek to organize themselves using the holding company structure. If a company organizes its individual State operations as divisions, then the restrictions of PUHCA do not apply. Thus Utilicorp United, Inc. (Kansas City, MO) has utility operations in nine States—States that are geographically diverse and non-contiguous. To the extent PUHCA restricts additional utility acquisitions, these are restrictions that the company itself assumed through its choice of corporate form."[43]

The utility merger trend has greatly accelerated over the past few years. Several of these mergers have occurred between exempt holding companies, several have resulted in the formation of new registered holding companies, and one even involved an acquisition by an already registered holding company. As of June 1, 1998, there were 19 registered holding companies, all headquartered in the eastern half of the United States, 10 of which were electric and three of which were gas. Six companies were a combination of the two (Figure A1 and Table A1).

There were 112 holding companies exempt from SEC regulation under the umbrella of PUHCA Section 3 (a)(1) which states that a holding company is exempt if *"such holding company, and every subsidiary company thereof ... are predominantly intrastate in character and carry on their business substantially in a single State in which such holding company and any such subsidiary company thereof are organized."*[44] Additionally, 39 holding companies were exempt under Section 3 (a) (2) which states that a holding company is exempt if *"such holding company is predominantly a public utility company whose operations ... do not extend beyond the State in which it is organized and States contiguous thereto."*[45]

The Call for Immediate PUHCA Reform[46]

It is argued that electric utility registered holding companies are not playing on a level field with other

[40] In the past, exempt holding companies have invested in security businesses, real estate, savings and loans, equipment supply, and even used car lots.

[41] M. Kanner, *PUHCA: Impact on Investments by Utilities*, http://www.citizen.org/cmep/restructuring/puhca/kanner.htm.

[42] N. J. Klauder, F. L. Norton, and M. K. Huntington, *Utility Mergers & Acquisitions*, A Competitive Utility Special Report (Infocast, Inc., May, 1999).

[43] *Ibid.*

[44] Public Utility Holding Company Act of 1935 (Public Law 74-333), Section 3.

[45] *Ibid.*

[46] Although PUHCA reform or outright repeal is being considered today because of the move to deregulate, the same plea for change has been made several times over the past 20 years. In the 1970s, utilities sought relief from PUHCA constraints in order to diversify into nonutility lines of business as a means to improve their declining profits. In the 1980s, they sought to diversify in order to exploit the positive experience of independent power producers under the Public Utility Regulatory Policies Act of 1978 (PURPA). In fact, the SEC has conducted studies on the validity of PUHCA in today's electric utility industry and, on several occasions, has recommended that the law be amended.

Figure A1. States Where Registered Holding Companies are Headquartered, as of June 1, 1998

Table A1. Registered Holding Companies, as of June 1, 1998

Registered Holding Companies / State of Incorporation	Public Utility Company Subsidiaries (State of Incorporation)	Type
Allegheny Energy, Inc. (AEI)/ MD	Monongahela Power Co. (OH) The Potomac Edison Co. (MD/VA) West Penn Power Co. (PA) Ohio Valley Electric Corp. (OH)	Electric
Ameren (AME) / MO	Union Electric Co. Central Illinois Public Service Co. (IL)	Electric & Gas
American Electric Power Co. (AEP) / NY	AEP Generating Co. (OH) Appalachian Power Co. (NY) Columbus Southern Power (OH) Indiana Michigan Power Co. (IN) Kentucky Power Co. (KY) Kingsport Power Co. (VA) Ohio Power Co. (OH) Wheeling Power Co. (WV)	Electric
Central and South West Corp. (CSW) / DE	Central Power and Light Co. (TX) Public Service Co. of Oklahoma (OK) Southwestern Electric Power Co. (DE) West Texas Utilities Co. (WV)	Electric
Cinergy Corp. (CIN) / DE	PSI Energy, Inc. (IN) The Cincinnati Gas & Electric Co. (OH)	Electric & Gas

Table A1. Registered Holding Companies, as of June 1, 1998 (continued)

Registered Holding Company / State of Incorporation	Public Utility Company Subsidiaries	Type
Columbia Energy Group (CEG) / DE	Columbia Gas of Kentucky (KY) Columbia Gas of Maryland, Inc. (DE) Columbia Gas of Ohio, Inc. (OH) Columbia Gas of Pennsylvania, Inc. (PA) Columbia Gas of VIrginia, Inc. (VA)	Gas
Conectiv (CON) / DE	Delmarva Power & Light Co. (DE) Atlantic City Electric Co. (NJ) Chesapeake Utilities Corp. (DE)	Electric & Gas
Consolidated Natural Gas Co. (CNG) / DE	The East Ohio Gas Co. (OH) The People's Natural Gas Co. (PA) Virginia Natural Gas Inc. (VA) Hope Gas, Inc. (WV)	Gas
Eastern Utilities Association (EUA) / MA	Blackstone Valley Electric Co. (RI) Newport Electric Corp. (RI) Eastern Edison Co. (MA) EUA Ocean State Corp. (RI)	Electric
Entergy Corp. (ENT) / FL	Entergy Arkansas (AR) Entergy Louisiana Power (AR) Entergy Operations, Inc. (DE) Entergy Power, Inc. (DE) Entergy Gulf States, Inc. (TX)	Electric
General Public Utilities Corp (GPU) / PA	Jersey Central Power & Light Co. (NJ) Metropolitan Edison Co. (PA) Pennsylvania Electric Co. (PA) GPU Nuclear Corp. (NJ)	Electric
Interstate Energy Corp. (IEC) / WI	Wisconsin Power & Light Co. (WI) Wisconsin River Power Co. (WI) Interstate Power Co. (IA) IES Utilities Co. (IA)	Electric & Gas
National Fuel Gas Co. (NFG) / NJ	National Fuel Gas Distribution Co. (NY)	Gas
New Century Energies (NCE) / DE	Public Service Co. of Colorado (CO) Southwestern Public Service Co. (NM) Cheyenne Light, Fuel, and Power Co. (WY)	Electric & Gas
New England Electric System (NEES) / MA	Granite State Electric Co. (NH) Massachusetts Electric Co. (MA) The Narragansett Electric Co. (RI) New England Electric Transmission Corp. (NH) The New England Power Co. (MA)	Electric
Northeast Utilities (NEU) / MA	The Connecticut Light & Power Co. (CT) Public Service Co. of New Hampshire (NH) Western Massachusetts Electric Co. (MA) North Atlantic Energy Corp. (NH) North Atlantic Energy Service Corp. (NH) Holyoke Water Power Co. (MA) Northeast Nuclear Energy Co. (CT)	Electric
PECO Energy Power Co. (PECO) / PA	Susquehanna Power Co. (MD)	Electric

Table A1. Registered Holding Companies, as of June 1, 1998 (continued)

Registered Holding Company / State of Incorporation	Public Utility Company Subsidiaries	Type
The Southern Co. (SOU) / DE	Alabama Power Co. (AL) Georgia Power Co. (GA) Gulf Power Co. (FL) Mississippi Power Co. (AL) Savannah Electric and Power Co. (GA) Southern Nuclear Operating Co. (DE)	Electric
Unitil Corp. (UNI) / NH	Concord Electric Co. (NH) Exeter & Hampton Electric Co. (NH) Fitchburg Gas and Electric Light Co. (MA) Unitil Power Corp. (NH)	Electric & Gas

Source: U.S. Securities and Exchange Commission.

electricity industry entities, such as qualifying facilities (QFs) and exempt wholesale generators (EWGs). QFs were mandated under the Public Utility Regulatory Policies Act of 1978 (PURPA) which eliminated PUHCA constraints on certain QFs.[47] EWGs were mandated under the Energy Policy Act of 1992, which significantly modified PUHCA by allowing both utilities and non-utilities qualifying as EWGs to build, own, and operate power plants for wholesaling electricity in more than one geographic area. This is a condition not available to holding companies which, under PUHCA, must restrict their operations to a single contiguous electricity system.[48] It is this unlevel field which is behind the push from certain groups to eliminate PUHCA's restrictions on holding companies. These groups believe that, in an atmosphere of open competition, everyone must be able to compete under the same rules and regulations.

Those groups who support immediate repeal of the law say that PUHCA impedes domestic investments, diverts capital overseas, and unnecessarily restricts certain multistate utilities from competing in businesses crucial to delivering energy-related services. In addition, the law imposes many unneeded restrictions and significant costs upon utilities, placing them at a competitive disadvantage. These restrictions can eliminate attractive business opportunities that might save money for customers and enhance profits for shareholders. Since PUHCA requires prior approval from the SEC before company affiliates or subsidiaries can enter into contracts with each other, opportunities to reduce costs or operate with efficiencies cannot always be realized. (See the inset box for information regarding two bills which propose immediate repeal of PUHCA that have been introduced into the current Congress.)

S.313 - The Public Utility Holding Company Act of 1999 - introduced by Senator Richard C. Shelby (R-AL) on January 27, 1999; to repeal The Public Utility Holding Company Act of 1935 and to enact The Public Utility Holding Company Act of 1999.

H.R.2363 - The Public Utility Holding Company Act of 1999 - introduced by Congressman W.J. (Billy) Tauzin (R-LA) on June 25, 1999; to repeal The Public Utility Holding Company Act of 1935 and to enact The Public Utility Holding Company Act of 1999.

PUHCA Reform Must Wait

Those who are against PUHCA reform are mainly concerned about the timing. Repealing the law prior to the promulgation of comprehensive electricity reform legislation, which would contain necessary safeguards to protect consumers and the environment, would enable today's monopoly utilities to garner even more market power. Mergers reduce the number of competitors and mergers would grow if the law were repealed; therefore, competition might be meaningless. Right now, it is believed by some groups to be the only Federal law that protects consumers and the environment from market power abuses by the utility sector.

[47] For an explanation of "qualifying facilities" and the Public Utility Regulatory Policies Act of 1978, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry, An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 27-28.

[48] For an explanation of "exempt wholesale generators" and the Energy Policy Act of 1992, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry, An Update*, DOE/EIA-0562(96) (Washington, DC, December 1996), pp. 28-29.

In light of the recent wave of mergers, it is feared that there could be a handful of competitors with substantial market power. Repealing PUHCA without replacing it with a modernized version with strong market power protections could result in the acceleration of mergers, acquisitions, and consolidation. A likely result, according to some groups, would be higher electricity bills for consumers and more layoffs for workers. Those factions who promote immediate PUHCA repeal say that today there are measures that give the States the power to regulate holding companies, but anti-repeal supporters say the States may have the authority but they do not have the resources.

The following bills (most of which include provisions for PUHCA reform) take a comprehensive approach to electricity industry restructuring and are pending before the current Congress:

PENDING BEFORE THE U.S. HOUSE OF REPRESENTATIVES:

H.R.341 – "The Environmental Priorities Act of 1999" – introduced by Congressman Robert E. Andrews (D-NJ) on January 19, 1999; to establish a Fund for Environmental Priorities to be funded by a portion of the consumer savings resulting from retail electricity choice.

H.R.667 – "The Power Bill" – introduced by Congressman Richard Burr (R-NC) on February 10, 1999; to remove Federal impediments to retail competition in the electric power industry, thereby providing opportunities within electricity restructuring.

H.R.971 – "The Electric Power Consumer Rate Relief Act of 1999" – introduced by Congressman James T. Walsh (R-NY) on March 3, 1999; to amend the Public Utility Regulatory Policies Act of 1978 to protect the Nation's electricity ratepayers by ensuring that rates charged by qualifying small power producers and qualifying cogenerators do not exceed the incremental cost to the purchasing utility of alternative electric energy at the time of delivery.

H.R.1138 – "The Ratepayer Protection Act" – introduced by Congressman Cliff Stearns (R-FL) on March 16, 1999; to prospectively repeal Section 210 of the Public Utility Regulatory Policies Act of 1978.

H.R.1486 – "The Power Marketing Administration Reform Act of 1999" – introduced by Congressman Bob Franks (R-NJ) on April 20, 1999; to provide for a transition to market-based rates for power sold by the Federal Power Marketing Administrations and the Tennessee Valley Authority.

H.R.1587 – "The Electric Energy Empowerment Act of 1999" – introduced by Congressman Cliff Stearns (R-FL) on April 27, 1999; to encourage States to establish competitive retail markets for electricity, to clarify the roles of the Federal Government and the States in retail electricity markets, and to remove certain Federal barriers to competition.

H.R.1828 – "The Comprehensive Electricity Competition Act" – introduced by Congressman Thomas J. Bliley, Jr. (R-VA) on May 17, 1999; to provide for a more competitive electric power industry.

H.R.2050 – "The Electric Consumers' Power to Choose Act of 1999" – introduced by Congressman Steve Largent (R-OK) on June 8, 1999; to provide consumers with a reliable source of electricity and a choice of electric providers.

H.R.2569 – "The Fair Energy Competition Act of 1999" – introduced by Congressman Frank Pallone, Jr. (D-NJ) on July 20, 1999; to enhance the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency.

H.R.2602 – "The National Electricity Interstate Transmission Reliability Act" – introduced by Congressman Albert R. Wynn (D-MD) on July 22, 1999; to amend the Federal Power Act with respect to electric reliability and oversight.

H.R.2645 – "The Electricity Consumer, Worker, and Environmental Protection Act of 1999" – introduced by Congressman Dennis J. Kucinich (D-OH) on July 29, 1999; to provide for the restructuring of the electric power industry.

H.R.2734 – "The Community Choice for Electricity Act of 1999" – introduced by Congressman Sherrod Brown (D-OH) on August 5, 1999; to allow local government entities to serve as nonprofit aggregators of electricity services on behalf of their citizens.

H.R.2786 – "The Interstate Transmission Act" – introduced by Congressman Thomas C. Sawyer (D-OH) on August 5, 1999; to provide for expansion of electricity transmission networks in order to support competitive electricity markets and to bring the benefits of less regulation of such markets to the public.

H.R.2944 – (No short title) - introduced by Congressman Joe Barton (R-TX) on September 24, 1999; to promote competition in electricity markets and to provide consumers with a reliable source of electricity.

PENDING BEFORE THE U.S. SENATE:

S.161 – "The Power Marketing Administration Reform Act of 1999" –introduced by Senator Daniel P. Moynihan (D-NY) on January 19, 1999; to provide for a transition to market-based rates for power sold by Federal Power Marketing Administrations and the Tennessee Valley Authority.

S.282 – "The Transition to Competition in the Electric Industry Act" – introduced by Senator Connie Mack (R-FL) on January 21, 1999; to provide that no electric utility shall be required to enter into a new contract or obligation to purchase or to sell electricity or capacity under Section 210 of the Public Utility Regulatory Policies Act of 1978.

S.516 – "The Electric Utility Restructuring Empowerment and Competitiveness Act of 1999" – introduced by Senator Craig Thomas (R-WY) on March 3, 1999; to benefit consumers by promoting competition in the electric power industry.

S.1047 – "The Comprehensive Electricity Competition Act" – introduced by Senator Frank Murkowski (R-AK) on May 13, 1999; to provide for a more competitive electric power industry.

S.1048 – "The Comprehensive Electricity Competition Tax Act" – introduced by Senator Frank Murkowski (R-AK) on May 13, 1999; to provide for a more competitive electric power industry.

S.1273 – "The Federal Power Act Amendments of 1999" – introduced by Senator Jeff Bingaman (D-NM) on June 24, 1999; to amend the Federal Power Act and to facilitate the transition to more competitive and efficient electric power markets.

S.1284 – "The Electric Consumer Choice Act" – introduced by Senator Don Nickles (R-OK) on June 24, 1999; to amend the Federal Power Act to ensure that no State may establish, maintain, or enforce on behalf of any electric utility an exclusive right to sell electric energy or otherwise unduly discriminate against any consumer who seeks to purchase electric energy in interstate commerce from any supplier.

S.1323 – "The TVA Customer Protection Act" – introduced by Senator Mitch McConnell (R-KY) on July 1, 1999; to amend the Federal Power Act to ensure that certain Federal power customers are provided protection by the Federal Energy Regulatory Commission.

S.1369 – "The Clean Energy Act of 1999" – introduced by Senator James M. Jeffords (R-VT) on July 14, 1999; to enhance the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency.

Appendix B

Three Case Studies of Electric Utility Divestiture of Power Generation Assets

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Three Case Studies of Electric Utility Divestiture of Power Generation Assets

Since late 1997, investor-owned utilities have been divesting power generation assets in record numbers. The process of selling large power plants is complicated, and the outcome of the sale is important to electricity customers (i.e. ratepayers) and utility owners. This appendix presents three case studies describing the process of divesting power plants.

Case 1: Central Maine Power

Maine's restructuring law (LD 1804) requires divestiture of all generation by utilities. Exceptions are allowed for certain power purchase contracts, nuclear power plants, sites outside of the United States, and plants deemed by the Maine Public Utility Commission (PUC) to be necessary for reliable performance of the utility's obligations. To respond to this law, Central Maine Power (CMP) placed its entire 2,110 MW asset portfolio up for auction. A total of 1,121 MW were sold in the initial auction. (See box for more details on CMP's asset divestitures.) CMP is still seeking buyers for the remaining assets. However, of the remaining 989 MW, only 127 MW must be divested.

Seller:	Central Maine Power
Asset:	1,121 MW (which included 373 MW hydro, 717 MW oil, and 31 MW wood)
Buyer:	FPL Energy (a subsidiary of FPL Group)
Details:	Purchase price was $846 million (book value was $218.9 million at the end of 1998); an appended agreement sold storage facilities for $3.6 million (book value was $11.9 million)

The sale opened in May, 1997 with CMP's entire 2,110 MW portfolio of generation assets on the market, packaged by fuel type: fossil, hydro, biomass, nuclear, and power contracts. This included 862 MW of nuclear and power contract generation assets which were exempt from the mandated divestiture. Final bids were submitted in early December, 1997 and one month later CMP announced that FPL Energy had been selected to buy the fossil, hydro, and biomass packages. No buyers were selected for either the nuclear or power contract assets as CMP deemed none of the offers to be adequate. Approval by the Maine PUC and by the Federal Energy Regulatory Commission (FERC) came in November, 1998. The sale closed in April, 1999.

This sale was highly controversial because of an appended Letter of Agreement between CMP and FPL in which CMP agreed to use its vote within the New England Power Pool (NEPOOL) to lobby for FPL's interests until the FERC approved new guidelines for transmission access in the deregulated market. FPL was trying to maintain the priority of access to transmission lines that CMP had enjoyed under regulation. Some intervenors feared that this agreement, if allowed, would effectively put FPL in NEPOOL, giving it an advantage over other generators and violating the spirit, if not the letter, of Maine's restructuring law. CMP, however, saw the agreement as strictly limited in time and scope, and the PUC approved the sale, including the letter, on that basis.

In October, 1998, the FERC did issue a ruling on NEPOOL's transmission access rules, ordering NEPOOL to revise the rules to lessen the burden on new generators connecting to the system. FPL felt that the ruling revoked the priority access that the CMP plants had previously enjoyed and considered this to be sufficiently harmful to the value of the plants that it filed suit in Federal court seeking a declaratory judgement voiding the purchase contract. The court ruled in favor of CMP in April, 1999. FPL chose not to pursue the matter and closed the sale later that month.

The Auction Process

Public announcements and personal contacts with potentially interested bidders were used to generate interest in the sale. The assets were grouped by generation type to hold down the transaction costs of the sale. In phase I, a memo and reference manual for the auction were sent to all qualified bidders in June, 1997. Also, a document center was set up for bidders to review more detailed information on the plants. Tours of selected plants were conducted as part of the process. Non-binding bids were due by September 10, 1997. CMP and its financial advisor, Dillon Read, then reviewed these bids and selected final round bidders based on: 1) price offered, 2) financial ability of the bidder, 3) degree of deviation from the terms and conditions of the offering memorandum, 4) continued opportunities for current CMP employees, 5) flexibility to negotiate savings in power contracts, 6) assumption of CMP's collective bargaining agreement, and 7) ability of bidder to operate assets reliably in a competitive environment. In phase II, selected bidders were sent an information packet with detailed financial information and a purchase / sale agreement form with terms / conditions that should be considered in submitting the final, binding bid. Phase II bids were due by December 10, 1997. CMP indicated that it would consider bids for partial packages, but clear preference would be given to bids made for complete packages.

The two-stage process was chosen to improve the chances of attracting serious bids. The first stage eliminates those unlikely to prevail, improving the odds for the remainder and increasing the resources they are willing to devote to a serious bid. However, the number of bidders must not be so low that their resources are devoted not to evaluating the assets but to forecasting their competitor's bid. CMP feared that this would generally lower the level of the bids.

Bundling assets was a method used to reduce administrative costs and improve chances for selling all assets. (In this method, low-value assets that will attract few, if any, bids are bundled with high-value ones.) Bundling may harm the total value of the assets if there are multiple buyers with different valuations for each plant, and all plants are valued by some bidders. (For example, Cape Station may have had more value as a pure real estate deal than as part of a power plant package.) CMP attempted to reduce this drawback by encouraging those wishing to bid on partial packages to form coalitions to bid on the entire package. This had the added benefit of reducing the number of bids to be considered.

CMP's plan was to file for approval of the sale within 45 days of choosing the buyer and get PUC approval within 7 months of filing. The PUC found this timeline feasible providing the filing contained sufficiently complete and detailed information, including the complete purchase / sale agreement, an analysis showing that the sale maximizes asset value obtained, an analysis of replacement power for the interim between closing the sale and the opening of competition, and an analysis of the sale's impact on market power.

The selling price of the assets was substantially above their book value. Book value of the assets was approximately $231 million, and the selling price was $846 million. In part, this is due to the hydro assets which have a very low book value but are still in excellent operating condition. Maine's requirement that all power providers include at least 30 percent renewable power in their supply portfolio would also have pushed up the price. Third, FPL Energy's belief that existing generation assets would have priority access to the transmission grid increased the price they bid. CMP will use the proceeds of the sale to retire debt and perhaps finance a rate reduction.

FPL's plans for the assets include upgrading or replacing some of the older units and building 1,500 MW of new generating capacity on the sites.

Case 2: Pacific Gas & Electric Company

California's restructuring law (AB 1890) does not explicitly require divestiture. However, it does call for separation of transmission and generation, and it does require that no generator in the restructured market be able to exercise significant market power. Because of Pacific Gas & Electric's (PG&E's) size (the total nameplate capacity of its generation assets was over 14,000 MW), the California Public Utility Commission directed PG&E to voluntarily divest at least 50 percent of its fossil generation to mitigate its market power. PG&E chose to divest virtually all of its fossil generation, keeping only the 105 MW Humboldt Bay gas plant. (See box for more details on PG&E's asset divestitures.) (Because it is located on the site of a decommissioned nuclear plant, its sale would involve an excessive amount of regulatory red tape.) The sale was conducted in two auctions, splitting the plants among three buyers. The final stage in PG&E's generation restructuring is the auction of its hydroelectric generating assets. PG&E is keeping the 2,200 MW El Diablo nuclear plant.

PG&E's initial auction, proposed in October, 1996, offered four fossil plants for sale: Moss Landing, Morro Bay, Oakland, and Hunter's Point. In June, 1997, Hunter's Point was withdrawn from the initial auction and added to a proposed second auction which offered four more plants for sale: Potrero, Pittsburg, and Contra

Seller: Pacific Gas & Electric	
Asset:	2,645 MW (which included Moss Landing [1,478 MW gas], Morro Bay [1,002 MW gas], and Oakland [165 MW oil])
Buyer:	Duke Energy Power Services
Details:	Sold for $501 million (book value was $346 million); sale closed in July, 1998
Asset:	3,065 MW (which included Potrero [363 MW], Contra Costa [680 MW], and Pittsburg [2,022 MW], all gas-fired)
Buyer:	Southern Energy (a subsidiary of Southern Co)
Details:	Potrero, Contra Costa, and Pittsburg sold for $801 million (book value was $256 million); sale closed in April, 1999
Asset:	The Geysers (1,224 MW geothermal)
Buyer:	Calpine Energy
Details:	Sold for $213 million (book value was $245 million); sale closed in May, 1999
Asset:	El Dorado (21 MW hydro)
Buyer:	El Dorado Irrigation District (EID)
Details:	Sold for $1 (book value was $50.8 million); PG&E pays EID $17 million to close the plant
Asset:	68 hydro plants (3,890 MW hydro)
Details:	Book value $800 million; market value expected to be in the $3-$5 billion range

Costa (all fossil plants), and the Geysers geothermal plants. The first auction began in September, 1997 and concluded with the November announcement that Duke Energy had been selected as the buyer. The sale generated little controversy and closed in July, 1998. The second auction began in April, 1998 and concluded in November, 1998 with Southern Energy selected to buy the fossil plants, and FPL Energy the geothermal plants. Subsequently, Calpine, owner of the geothermal steam fields that supply the Geysers plants, exercised its right of first refusal and supplanted FPL as the buyer of Geysers. The Southern Energy sale closed in April, 1999 and the Calpine sale in May, 1999.

The controversy in these auctions revolved around the Hunter's Point and Potrero plants. Both are old and inefficient, located in minority neighborhoods in San Francisco, and the subjects of repeated complaints that they pose a health hazard to the residents. They are also both "must run" plants, required for the reliable supply of power to the San Francisco area. (A transmission bottleneck limits the amount of power that can be delivered from outside.) San Francisco was afraid that the new owner would increase generation at the plants to maximize its revenue at the expense of the health of the residents. The city sought to buy the plants itself, but was late submitting a bid, and the PUC would not give it special status. After the city threatened to exercise its right of eminent domain to break the impasse, PG&E agreed to withdraw Hunter's Point from the sale and close it down as soon as its "must run" status could be removed.

The Auction Process

On the advice of its financial advisor for the divestiture, Morgan Stanley, PG&E proposed a two-stage open auction for both auctions. The basic format of both auctions was the same. In stage 1, PG&E publicized the sale to potential bidders, providing basic information on the assets to be sold and the terms and conditions of the sales agreement. Interested bidders provided PG&E with evidence of their financial and operational qualifications, and a nonbinding bid. In the first auction, bids could be placed on any combination of plants; in the second, Pittsburg and Contra Costa were bundled as a single unit and separate bids were required for the Lake County and Sonoma County units of the Geysers geothermal plant. PG&E chose 5-10 final round bidders for each plant. In the second stage, PG&E provided detailed information in support of the due diligence being conducted by the bidders. At this time, the bidders were allowed to propose changes in the sales agreement—PG&E issued the final form of the agreement two weeks prior to the final bid due date. Each plant was sold to the highest bidder, assuming PG&E's reservation price was met and no unacceptable conditions were subsequently imposed by the reviewing agencies.

In cases where significant environmental impact is a possibility, California's Environmental Quality Act requires an Environmental Impact Report to be completed by the PUC, detailing mitigation requirements. This was done for the second auction, in large part because of the controversy over Hunter's Point and Potrero. Remediation costs totaling nearly $90 million were imposed on PG&E, which it may recover through the Competitive Transition Charge.[49]

[49] This is a charge to the ratepayer to cover a utility's costs as a result of California's electricity industry restructuring program.

The California PUC is also charged with ensuring that the deregulated electric power system will continue to run reliably and that no generator will be able to exercise market power. The distribution of PG&E's assets among three buyers satisfied the goal of mitigating market power. The reliability question is handled in part through the designation of some plants as "must run" status plants, which places obligations on the owner of the plant. California's restructuring law also contributes to the continuity and reliability of plant operation by requiring the new owner to contract with the old owner to operate the plant for two years from the closing of the sale. Lastly, the requirement of proof of operational expertise at stage 1 of the auction to be considered a qualified bidder helped satisfy the goal of continued reliability.

In November, 1998 PG&E began the final phase of its divestiture, submitting a plan to transfer its hydroelectric generation to its unregulated affiliate, PG&E Generating. PG&E chose to divest via transfer rather than auction for economic reasons. First, it was thought that the transfer could be accomplished in as little as 6 months, compared to over 2 years to complete the auction process. This would allow PG&E to end its stranded cost recovery, and thus its rate freeze, well before the March 31, 2002 deadline. Second, the transfer avoids the large Federal capital gains taxes that would be due if the plants were sold at auction. These savings would be applied to PG&E's stranded costs, benefitting California's ratepayers. The value of the transferred assets was to be assessed by outside experts, as required by California's restructuring law.

This plan was highly controversial and drew criticism from environmentalists, consumer groups, municipalities, State regulators and State legislators, all staking a claim to what was expected to be a very valuable asset. The Association of California Water Agencies (ACWA) assessed the value of the plants at between $3.14 billion and $4.34 billion. The ACWA saw no merit to market power criticisms of a transfer, but warned that the relicensing of the plants would likely reduce their value, either through increased environmental mitigation costs or through reduced generation capability. Several bills were introduced into the California Legislature championing various sides of the issue, including one by PG&E and its allies seeking approval for the transfer. The PG&E bill proposed setting the plant's value at $3.3 billion, about $2.5 billion above book value. However, the 1999 legislative session ended without any action having been taken. On September 30, 1999 PG&E filed an application with the PUC outlining an auction plan for the hydroelectric plants, splitting them into 20 bundles. PG&E Generating would participate in this auction.

The El Dorado hydroelectric project has been separated from the rest of the hydroelectric system and sold. It had suffered severe damage from winter storms in recent years and PG&E decided it was not economically worthwhile to repair the damage. The "buyer," El Dorado Irrigation District, bought El Dorado to obtain the water delivery assets of the project and plans to dismantle the power plant.

With the exception of El Dorado and Geysers, all plants sold brought in considerably more than their book value. For example, the Potrero, Costa, and Pittsburg power plants sold for $801 million. Their book value was $256 million. The reason for El Dorado's low price was noted above. In the case of the Geysers, the likely reason is supply constraints on capacity utilization. Although rated at 1,224 MW, the current condition of the geothermal steam fields supplying the plants restrict their effective capacity to 665 MW. The net excess of price over book value plus transaction costs will be used to lower PG&E's stranded costs. Calpine, owner of the Geysers steam fields, purchased the power plants in order to unify steam field and power plant operations, reducing costs to California consumers and extending the life of the assets. Duke and Southern both plan on actively participating in the merchant power market in California. They are somewhat constrained by the "must run" status of most of their units and environmental restrictions on the operation of others (Potrero and Pittsburg). Several of the older units will probably be upgraded or replaced with new, larger units.

Case 3: Portland General Electric

In 1996, the Governor of Oregon issued a statement of principles as a guideline to restructuring. However, the Oregon legislature has not yet passed restructuring legislation. To adapt to the new environment, Portland General Electric (PGE) is voluntarily divesting all of its generation assets. It intends to become a regulated transmission and distribution company and thus is seeking to sell all of its generation and related assets.

PGE filed its divestiture plan with the Oregon PUC in September, 1997, choosing Merrill Lynch to serve as its financial advisor in the sale. By taking advantage of the current excess demand for generation assets, PGE, like General Public Utilities System and Montana Power, hopes to realize a premium on the sale of their assets before the increasing number of States with restructuring laws that require divestiture glut the market and bring prices back down. (See box for more details on PGE's asset divestitures.)

Seller:Portland (Oregon) General Electric (a subsidiary of Enron Corporation)

Asset:	3,030 MW of generation and supply contracts, split into 5 packages (which included Boardman [330 MW coal], Beaver, Bethel, and Coyote Springs [830 MW gas/waste], Pelton and Round Butte [408 MW, hydro], Clackamas, Bull Run and Sullivan [202 MW hydro], and 1,260 MW of generation contracts)
Asset:	323 MW share of Colstrip (coal)
Buyer:	PP&L Global, Inc
Details:	Sold in conjunction with shares of Montana Power and Puget Sound Energy in November, 1998; PGE's share of the price was $230.5 million (book value was $219 million)
Asset:	33.5 MW share of Centralia (coal)
Buyer:	TransAlta
Details:	Sold in conjunction with the other 7 owners of the plant in May 1999; PGE's share of the sale price was $13.85 million (book value was $4 million)

The Auction Process

PGE proposed a two-stage auction process for qualified bidders, with sealed bids, and selection made on the basis of price plus imputed value of other terms and conditions. They favor a two-stage auction because: (1) it is expensive to develop binding bids on generation assets and bidders are unlikely to commit the necessary resources until they have some indication that their chances of success are reasonable, and (2) conducting due diligence is expensive for the seller as well, as they must make company resources and senior officials available to all bidders. The use of nonbinding first-round bids to filter out weak bidders quickly reduces the cost of exploring a sale, provides the second round bidders with the signal they need that their chances are reasonable, and cuts administrative costs to the seller. Sealed bids help the company to maximize value received for the assets—in a public auction the winning bid will almost surely be only slightly larger than the second place bid, even if the winner was willing to go much higher to acquire the assets. The use of imputed value for the other terms and conditions of the sale, rather than price only, helps maximize the overall value of the sale and improves the chances of obtaining regulatory approval in cases where these conditions are important to the community.

PGE's plan was partially approved by the Oregon PUC in January, 1999. The divestiture of fossil assets and power contracts was not controversial and was approved. However, the proposed divestiture of hydroelectric generation was controversial.

The Oregon PUC agreed with the intervenors that the sale of PGE's hydroelectric assets was not in the best interest of the State. The issues they cited were:

(1) The sale would have an adverse impact on and would be adversely impacted by the relicensing of the hydroelectric projects. In particular, the PUC felt the sale was likely to delay the relicensing process, despite the FERC's assurances to the contrary. Further, the uncertainties of the relicensing process would likely lower the bids for hydroelectric plants, as would knowledge that the sale would receive close scrutiny by the PUC.

(2) Hydroelectric's low cost is a major reason that Oregon's electricity rates are among the lowest in the Nation. The PUC felt complete merchant status for all generation would almost surely raise average prices, mostly to residential customers. Retaining the hydroelectric plants would lower Oregon's dependence on market purchases and reduce price volatility.

(3) Properly evaluating and allocating the sale's benefits is difficult. The PUC felt mixed sales of hydroelectric and fossil plants would make it difficult to ensure that the hydroelectric assets were properly valued. Further, it argued that since the sale is not reversible, if the anticipated benefits did not appear, it would be too late to backtrack. Finally, PGE's plan was to amortize the benefits over 5 years; the PUC argued that, because of the long life of hydroelectric assets, this would deny the benefits of the sale to many future users of the power from those plants.

As an alternative to the sale of the plants to an outside company, the PUC offered a plan in which the hydroelectric assets would be spun off to an affiliated generating company of PGE.

At present, PGE is awaiting the action of the Oregon legislature before deciding on how to proceed with its planned divestiture. Because of the expense in bidding on generation assets, the support of the PUC is an important element in attracting good bids. If it is likely that the PUC will not approve the sale, or place expensive conditions on it, then the assets become less valuable to the bidder. Bids will be lowered in compensation for these expected additional costs, and fewer resources will be committed to generating a bid.

The sales of PGE's shares of the Centralia and Colstrip plants were conducted separately from the proposed auction of PGE's other assets. Each was sold in conjunction with shares held by the other owners of the plants, in order to maximize the sale value. That is, selling a majority stake in a plant will likely attract better bids than the separate sale of several minority stakes.

Appendix C

1994 Merger of Cincinnati Gas & Electric Company and PSI Resources, Incorporated into CINergy Corporation

Appendix C
Case Study[50]

1994 Merger of Cincinnati Gas & Electric Company and PSI Resources, Incorporated into CINergy Corporation

In 1994 Cincinnati Gas & Electric Company (CG&E) merged with PSI Resources, Incorporated, to form a new registered holding company, CINergy Corporation (CINergy). The focus of this case study is to determine, using public data, if the objectives of the merger were realized. As proposed, the objectives were: (1) to receive the benefit of $750 million in cost savings expected over the 1994-2003 period; (2) to lower electricity rates for customers and enhance returns on stock equity for shareholders due to the cost savings; and (3) to create a larger, more efficient utility to better meet the challenges of a more competitive environment.[51]

Data sources for the analysis were: (1) Federal Energy Regulatory Commission (FERC): Merger Application and Testimony and FERC Form 1, (2) Securities and Exchange Commission: 10K filings, and (3) annual reports published by the merging companies.

Description of the Companies

Cincinnati Gas & Electric Company: CG&E is an investor-owned gas and electric public utility incorporated in Ohio. It is a major utility[52] engaged in the production, transmission, distribution, and sale of electricity, and the transportation and sale of natural gas, to customers within Ohio. In addition to approximately 590,000 retail electricity customers, CG&E was under contract to satisfy full requirements of six municipal customers and two CG&E utility subsidiaries. Almost all of CG&E's electricity was produced by coal-fired generation plants. CG&E had four wholly-owned public utility subsidiaries and two wholly-owned non-utility subsidiaries when the merger closed. The four public utility subsidiaries were: Union Light, Heat and Power Company (Union), Miami Power Corporation (Miami), West Harrison Gas and Electric Company (West Harrison), and Lawrenceburg Gas Company (Lawrenceburg). The two nonutility companies were KO Transmission Company (formed in 1994 to become part-owner of an interstate gas pipeline company) and Tri-State Improvement Company (a company for acquiring and holding real estate in support of CG&E's utility operations).

Union Light, Heat, and Power, also a major investor-owned public utility, is smaller than CG&E and owns no generation plants. At the close of the merger, Union purchased all of its electricity from its parent company, CG&E. Union engages in the transmission and distribution of electricity within Kentucky. During 1994, Union served approximately 110,000 retail electricity consumers and one full-requirements wholesale municipal customer.

[50] This case study was adapted from a report prepared under contract to the Energy Information Administration, U.S. Department of Energy.

[51] Source: Prepared direct testimony of Jackson H. Randolph, President and Chief Executive Officer, The Cincinnati Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC93-6, December 21, 1992, pages 6 and 7.

[52] The term "major utility" is used here to denote a major utility for reporting purposes under FERC Form 1, the primary source of data used as a basis for this merger analysis. Under FERC Form 1, a major utility had, in each of the last three consecutive years, sales or transmission service that exceeded one of the following: (1) 1 million megawatthours of total annual sales; (2) 100 megawatthours of annual sales for resale; (3) 500 megawatthours of annual power exchanges delivered; or (4) 500 megawatthours of annual wheeling for others (deliveries plus losses).

Miami, West Harrison, and Lawrenceburg are small utilities. At the close of the merger, Miami owned a 138-kV electric transmission line running from the Miami Fort Power Station to a point near Madison, Indiana. It is regulated by the FERC. West Harrison sold electricity over a 3-square-mile area, with a population of approximately 1,000, in southeastern Indiana. Lawrenceburg sold natural gas over a 60-square-mile area, with a population of 20,000, in southeastern Indiana.

PSI Resources, Incorporated: Prior to the merger, PSI Resources, Inc. was the parent company of PSI Energy, Inc. (PSI Energy), an electric utility serving Indiana. PSI Energy was approximately the same size utility as CG&E. In addition to approximately 630,000 retail electric customers within Indiana, PSI also supplied electric power for resale to municipal customers, rural electric membership corporations, the Wabash Valley Power Association (WVPA), and the Indiana Municipal Power Agency (IMPA). PSI owned its high-voltage transmission system as a tenant in common with IMPA and WVPA. In 1994, over 99 percent of PSI's electricity was produced in coal-fired plants; the remainder was hydroelectric generation. PSI Energy is regulated by the FERC for wholesale transactions, and by the Indian Utility Regulatory Commission (IURC) for retail electric rates.

At the time of the merger closure, PSI had two wholly-owned subsidiaries, PSI Energy Argentina, Inc. (formed to invest in foreign utility companies) and South Construction Company, Inc. (formed to hold title to real estate that was not used or useful in the conduct of PSI Energy's utility business).

CINergy Corporation: Following the merger, CINergy, a Delaware corporation, became the parent holding company for CG&E, PSI Energy, CINergy Investments, Inc. (CINergy Investments) and CINergy Services, Inc. (CINergy Services). PSI Resources, Inc. ceased to exist. The merger was accounted for as a pooling of interests, effected by an exchange of stock. Each preferred stock share of CG&E and PSI Resources, Inc. received one share of preferred stock of CINergy Corporation. One share of common stock of CG&E was converted into one common share of CINergy. Each common share of PSI Resources, Inc. was converted into 1.023 common shares of CINergy.

CINergy Investments, a nonutility subsidiary company, was created in 1994 to operate CINergy's nonutility subsidiaries and interests. These include utility management consulting services, utility investment services, demand-side management services, energy and fuel brokering services, and resource marketing services. CINergy Services was incorporated in 1994 to provide the companies of the CINergy system with a variety of administrative, management, and support services.

At the end of 1994, the newly formed CINergy had $8.15 billion in assets, $2.92 billion in annual operating revenues ($2.48 billion electric; $0.44 billion gas), $191 million in net income, and 8,868 employees.[53] CINergy became the 13th largest electric utility in the Nation at the time.

Pre-Merger Estimated Cost Savings and Transaction Costs

The merging companies estimated $750 million in cost savings over the 1994-2003 period[54] primarily from three sources: (1) $113 million from electricity production (including fuel savings) from the joint dispatch of electric generation plants and lower reserve margin requirements;[55] (2) $400 million in lower revenue requirements due to capital expenditure reductions achieved through the deferral of new electricity generation capacity;[56] and (3) $230 million in administrative cost savings due to the elimination of approximately 400 redundant labor positions. Other initially non-costed administrative merger savings were expected to be derived from materials management savings,

[53] Source: 1994 CINergy Corp. SEC 10-K.

[54] Source: Prepared direct testimony of James E. Rogers, President and Chief Executive Officer of PSI Energy, Inc. and its holding company, PSI Resources, Inc., before the Federal Energy Regulatory Commission, Docket No. EC93-6, December 22, 1992, pages 9 and 10.

[55] The joint dispatch of electricity generation plants allows the lowest cost plant of the merged entities to be brought on line to meet demand. The result is lower electricity production costs than the two firms would incur when operating separately to meet the same aggregate electricity demand. Also, lower operating costs are incurred when lower planning reserve margin requirements for the merged system result in the deferral of new generation capacity, allowing for the elimination of start-up and operating and maintenance costs of the deferred units.

[56] Revenue requirements as used here refers to annualized fixed charges associated with the construction cost of the deferred generation capacity that would have had to be recovered through higher electricity rates in the next rate case, if the generation capacity had not been deferred.

insurance premium savings, savings on software license fees, auditing and professional services, and lower capital expenditures on management information systems.[57] Before the FERC's approval of the merger in October 1994, the applicants had raised these cost savings estimates to approximately $1.3 to $1.5 billion, derived from: (1) combined production cost savings and lower revenue requirements due to deferral of new electricity generation capacity of $681 million (as compared to $513 million initially); (2) net personnel savings of $296 to $331.9 million based on workforce reductions of 400 to 450 positions, (3) non-labor cost savings of $239 to $357 million, and (4) avoided capital expenditure savings of $48.4 million (exclusive of generation capital expenditure and production cost savings).[58] These merger savings were expected to be shared approximately equally between CG&E (with Union) and PSI Energy.[59]

There was not the same precision in the estimated merger transaction costs and costs to achieve merger savings (hereinafter collectively referred to as "merger costs") put forth by the merger applicants.[60] Adoption of ratepayer "hold harmless" provisions within settlement agreements made effective at the wholesale and retail rate level diminished the potential of merger costs on the ratepayer. Under the hold harmless provisions, merger costs could only be charged to customers if they were fully offset by demonstrated merger benefits.

PSI Energy's merger transaction costs were estimated at $27 million over the 1994-2003 period; its costs to achieve merger savings were estimated at $21 million, yielding total merger costs of approximately $48 million over ten years.[61] During 1994, CG&E expensed $32 million of merger transaction costs and costs to achieve merger savings that were already incurred and were under the jurisdiction of the Public Utility Commission of Ohio (PUCO). Subsequent PUCO jurisdictional merger costs were to be expensed by CG&E in future years as incurred. The non-PUCO electric jurisdictional portion of merger costs was estimated at $14 million.[62] Therefore, by the end of 1994, total merger costs over the 1994-2003 period were estimated to be at least $46 million for CG&E (with Union), and $48 million for PSI Energy.

Allocation of Savings and Merger Costs to Customers and Shareholders

Each public utility regulatory commission provided formulas for allocating merger costs and savings between ratepayers and shareholders. These allocation formulas are worth noting because they may demonstrate the effects of the merger on electricity rates and shareholder returns on equity. The settlement agreement regarding the allocation formulas is usually complex and, therefore, only highlights of the formulas are discussed.

The Indiana Utility Regulatory Commission (IURC) approved a settlement agreement in February 1995 that effectively allocated net nonfuel merger savings 50/50 between customers and shareholders of PSI Energy. Retail customer base rate reductions were to begin immediately, and were scheduled to increase for three years. Fuel-related merger savings would be flowed through as incurred quarterly to the ratepayers via the fuel adjustment clause.[63] PUCO approved a settlement agreement in April 1994 which permitted CG&E to retain for the shareholders all of its electric nonfuel operation and maintenance (O&M) expense savings from the merger until 1999, in exchange for a moratorium on increases in base rates until that time. Fuel-cost-related merger savings would go directly to the ratepayers via the fuel adjustment clause as lower fuel costs were incurred.

[57] Source: Prepared direct testimony of Lester P. Silverman, Director, McKinsey & Company, Inc. on behalf of the merger applicants, before the Federal Energy Regulatory Commission, Docket EC93-6, December 22, 1992, pages 19 and 20.

[58] Source: Response of Applicants to Staff Request for Information, filed by PSI Energy, Inc., The Cincinnati Gas & Electric Co, Union Light, Heat & Power Co., and Miami Power Corp., before the Federal Energy Regulatory Commission, under Docket No. EC93-6, July 26, 1993, p.3.

[59] *Op. cit.*: 1994 CINergy Corp. SEC 10-K.

[60] Transaction costs are the expenses paid by the merging companies to implement and execute the merger.

[61] *Ibid.*

[62] *Ibid.*

[63] Fuel adjustment clauses usually provide for a quarterly adjustment to the fuel-cost test-year estimate used in the compilation of base rates, based on the actual cost of fuel purchased during a calendar quarter. The result of fuel adjustment clauses is to place the entire risk of volatility in fuel prices on the ratepayer. If the merger results in lower fuel costs due to more efficient fuel purchasing, these merger benefits would be entirely passed through to the ratepayers on their electric bills at the end of the period in which the lower fuel costs are realized.

In exchange for Kentucky Public Service Commission's (KPSC's) approval of the merger, Union accepted the KPSC's request for an electric rate moratorium commencing after Union's next rate case and extending to January 1, 2000. The KPSC also required CG&E and Union to agree that, for 12 months from consummation of the merger, no filings would be made to adjust CG&E's base purchase power rate charged to Union or Union's base electric rates. (As stated earlier in this report, at the time of the merger, Union purchased all of its electricity at wholesale from CG&E.) In July 1996, the KPSC issued an order authorizing a decrease in Union's electricity rates of approximately 1 percent to reflect a reduction in the cost of electricity purchased from CG&E.

As a condition of approval, the FERC made compliance with the plans of the merging entities to construct more high voltage (345 kV) transmission capacity mandatory in order to better integrate the two transmission systems, and to better allow for open access on CINergy's integrated system.

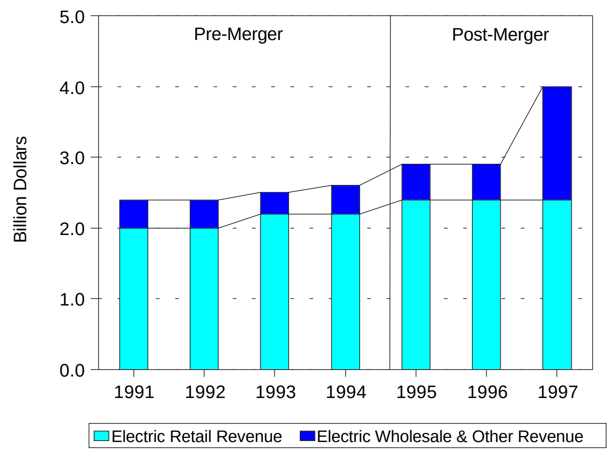
Effects of the Merger on CINergy's Overall Growth, Efficiency, and Profits

As described previously, one objective of the merger was to achieve net merger cost savings from greater efficiency in operations and administration, and thereby to increase equity returns to shareholders and reduce electricity rates to customers. Another objective was to better position the new company for increased competition in the utility industry. Achievement of better positioning is measured by the company's revenues, sales, and income after the merger.

Overall Growth Measurements

CINergy experienced a 3.1-percent annual growth in electric operating revenues before the merger (1991-1994), exceeding the 2.4 percent national average of investor-owned electric utilities (IOUs) (Figure C1). However, after the merger (1994-1997), annual electric operating revenues growth accelerated rapidly at 15.9 percent, far exceeding the corresponding national average growth for IOU's at 2.9 percent.[64] This acceleration in electricity revenue growth after the merger was derived from growth in wholesale revenues, which more than quadrupled.

Figure C1. CINergy's Operating Revenue, 1991-1997
(Nominal Dollars)



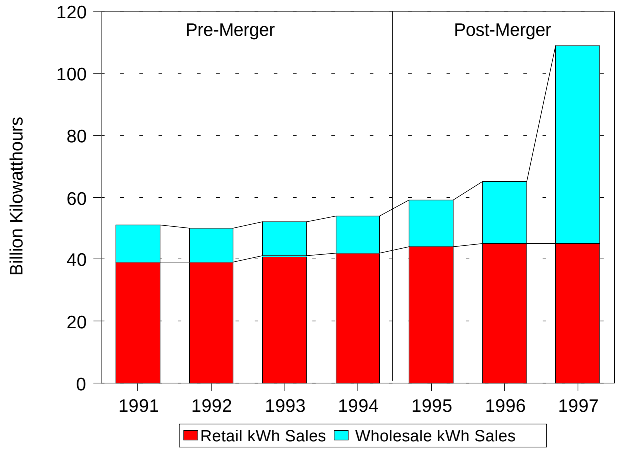
Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Growth in revenues after the merger was derived from rapidly growing wholesale sales of electricity. Annual wholesale sales before the merger were level, but after the merger they increased by more than a factor of five (Figure C2). The growth in wholesale sales is directly related to the growth in wholesale customers of CINergy's two subsidiaries with generation plants, namely PSI and CG&E (Figure C3).

Because CINergy integrated and opened access to its transmission system during the merger, some of the credit for these additional wholesale sales can be attributed to the merger itself. This is illustrated by CINergy's annual average growth in wholesale sales in the 1994-1996 period (before FERC Order 888 was fully implemented) of 20 percent, compared to the annual

[64] The source of all data, unless otherwise stated, is the Federal Energy Regulatory Commission's Form 1 primarily as reported within the EIA Financial Statistics of Major U.S. Investor-Owned Electric Utilities, or the EIA Electric Power Annual, corresponding to the years mentioned. The combined totals of the three major utility subsidiaries of CINergy represent the arithmetic sum of all accounts as reported by the individual electric utilities. Consequently, duplications exist to a limited extent in the composite totals. For example, the totals for operating revenues and megawatthour sales include intercorporate sales.

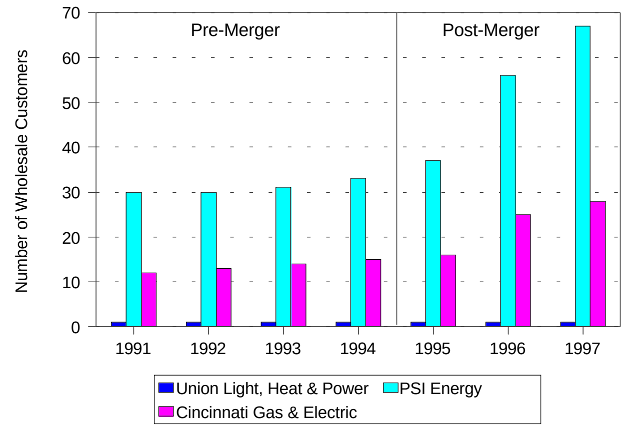
Figure C2. CINergy's Retail and Wholesale Electricity Kilowatthour Sales, 1991-1997



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.

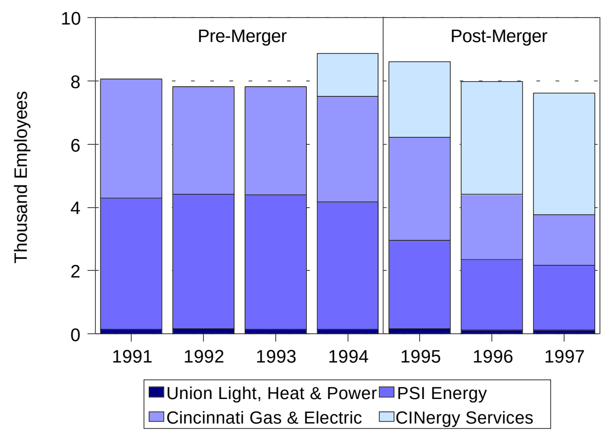
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure C3. CINergy's Subsidiaries' Wholesale Electricity Customers, 1991-1997



Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure C4. CINergy's Subsidiaries' Total Employees, 1991-1997



Note: CINergy Services was established as a subsidiary in 1994.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and the Securities and Exchange Commission, Form 10-K.

average growth in wholesale sales of all U.S. IOUs of 7.4 percent over the same period. The remainder of the credit for CINergy's five-fold growth in wholesale sales in the 1994-1997 period can be attributed to the FERC's success in opening competition within the wholesale market by issuing Orders 888 and 889 in 1996.

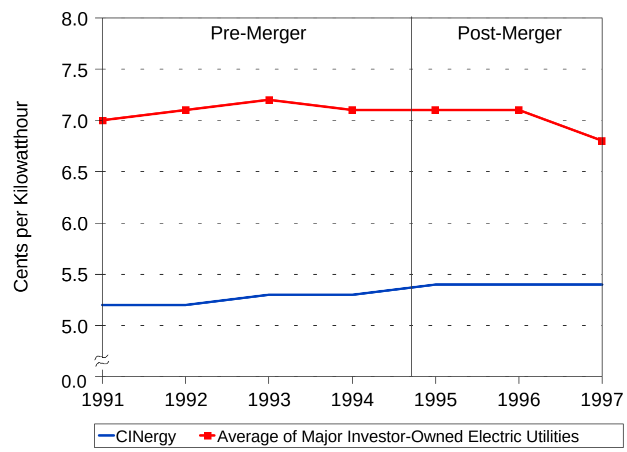
Although revenues, wholesale electricity sales, and wholesale customers grew rapidly after the merger, the size of the company, measured by the number employees, declined. In an effort to realize merger savings, CG&E and PSI Energy completed voluntary workforce reduction programs in both 1994 and 1996. As a result, the number of employees at the three utility subsidiaries was reduced by half from 1994 to 1997, dropping from 7,521 to 3,768 (Figure C4). Workforce reduction actually began within CG&E in 1992 before the merger.[65] In 1992, CG&E eliminated 464 positions through voluntary workforce reductions in order to become more manpower efficient. The number of employees attributed to the electric utility department by CG&E and Union combined decreased by 350 between 1991 and 1992. (CG&E itself reduced 381 electric department employees, while Union increased electric department employees by 30.)

Only looking at CINergy's electric utility subsidiaries overstates the reduction in manpower, however, because of the creation of a new subsidiary, CINergy Services, in 1994. CINergy Services was established to provide administrative and support services to all of CINergy's

[65] Op. cit., 1994 CINergy Corp. SEC 10-K; note 12 to financial statements.

subsidiaries, including the three major utilities. Some of the functions and positions attributed to the electric utility subsidiaries prior to the merger may have been transferred to CINergy Services after the reorganization in 1994.[66] Thus, a better indicator of the decline in manpower may be the reduction in total employees for all of CINergy, including all of its subsidiaries (utility and nonutility). After the merger (1994-1997), the total number of CINergy employees declined by 14.2 percent, from 8,868 to 7,609 (Figure C4).[67] Because CINergy has been aggressively pursuing a more diverse set of activities since the merger (e.g., national energy trading, foreign acquisitions, joint ventures, etc.),[68] which tends to increase the number of employees associated with nonutility subsidiaries, the true reduction in the workforce associated with electricity sales and services in the CG&E, Union, and PSI franchise areas is probably somewhere within the broad range of 14 percent to 50 percent.

Figure C5. CINergy's and Major Investor-Owned Electric Utilities' Retail Electricity Rates, 1991-1997
(Nominal Dollars)



Note: CINergy's data represent the sum of three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and the Energy Information Administration, *Electric Sales and Revenue 1997*, available on the Internet at www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html.

Overall Efficiency Measurements

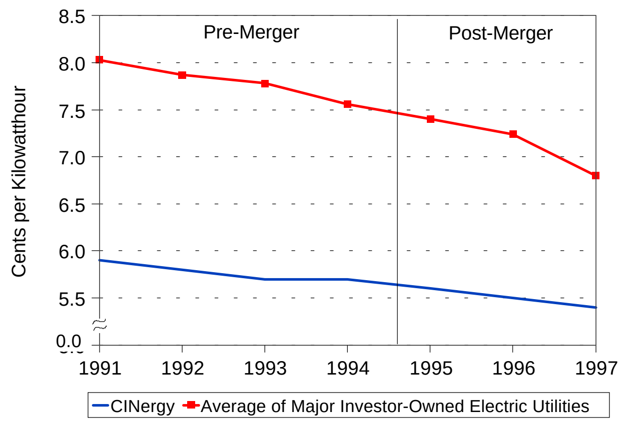
The most important efficiency measurement to a ratepayer is the change in retail customer electricity rates. Retail electricity rate is defined as the average revenue per kilowatthour of sales to retail customers. CINergy's average annual retail electricity rate before the merger was increasing 1.09 percent, and only 0.46 percent annually after the merger (Figure C5). The lower growth in CINergy's retail rates after the merger occurred primarily because of the moratorium on rate increase through January 1, 1999 agreed to by CG&E when the merger was approved by PUCO. CG&E's retail rates were growing at 4.0 percent annually before the merger, but after the merger they declined at 1.68 percent per year. While this shows a decline in retail growth rates due presumably to the merger, increasing rates after the merger are in contrast to declining retail rates for all IOUs over the same 1994-1997 period, at 0.13 percent per year.

The merger appears to have little to no effect when the rates are adjusted for inflation. CINergy's average rates were declining by 1.5 percent annually before and after the merger in 1997 dollars (Figure C6). Thus, the merger produced no demonstrable benefits to the ratepayer in the form of lower real rates. Further, the national average rates were declining at about 3.2 percent annually from 1994 to 1997—more than double the percent decrease experienced by CINergy.

A more direct measurement of efficiency gains in CINergy electricity production operations is found by inspecting changes in real operating and maintenance (O&M) costs. Prior to the merger, both major utilities with generation plants, PSI Energy and CG&E, were showing significant improvements in operational efficiency (Figure C7). From 1991 to 1994, PSI Energy reduced its real O&M costs by 3.1 percent annually, while CG&E showed an average annual reduction of 1.4 percent. When combined (although they were operating independently over much of this time), the real O&M

[66] This is referred to on p. 6 within the affidavit of Lester P. Silverman, as an attachment to the Response of Applicants to Staff Request for Information, before the Federal Energy Regulatory Commission, Docket No. EC93-6, July 26, 1993.
[67] Op. cit. 1994 CINergy Corp. SEC 10-K.
[68] A description of these new and more diverse activities is presented within CINergy's 1997 and 1998 Summary Annual Reports found on CINergy's website, http://www.cinergy.com. One notable example is a joint venture between Trigen Energy Corporation and CINergy formed in December 1996 to build, own, and operate co-generation and tri-generation facilities for industrial plants, office buildings, shopping centers, hospitals, etc., and for the provision of energy asset management services, including fuel procurement. Financial details of these new ventures can be found within the CINergy Corp. SEC 10-K for corresponding years.

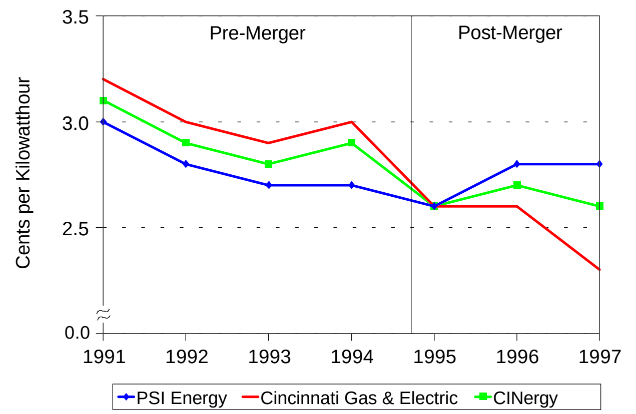
Figure C6. CINergy's and Major Investor-Owned Electric Utilities' Retail Electricity Rates, 1991-1997
(1997 Real Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and the Energy Information Administration, *Electric Sales and Revenue 1997*, available on the Internet at www.eia.doe.gov.

Figure C7. CINergy's and Subsidiaries' O&M Costs Minus Purchased Power Expenses, 1991-1997
(1997 Real Dollars)



Note 1: CINERGY's cost is the average of PSI Energy and Cincinnati Gas & Electric.

Note 2: Union Light, Heat, and Power does not generate power.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

cost declined by 2.4 percent annually. By the close of the merger, the two utilities were operating with coordinated generation dispatch, and the annual average efficiency gains under this measurement accelerated. Real O&M costs were reduced by an average annual rate of 3.7 percent between 1994 and 1997. As a result, by 1997, real O&M costs for the two utilities were 10.6 percent below the 1994 value, and 16.9 percent below the 1991 level.

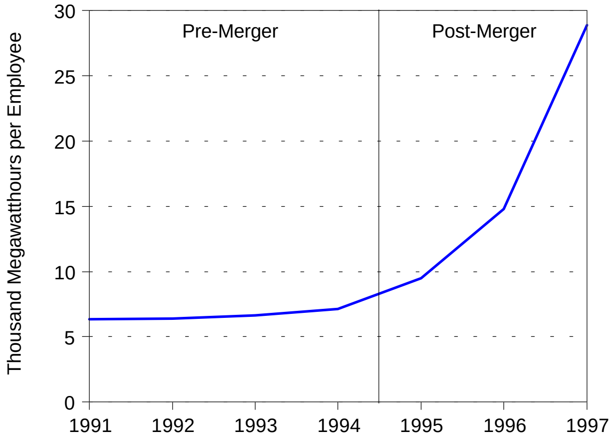
Because CINergy projected merger savings due to workforce reductions, it is worthwhile to inspect indicators of electric department employee efficiency before and after the merger.[69] CINergy's total megawatthours of sales (ultimate consumer sales and sales for resale) per electric utility department employee increased dramatically after the merger (Figure C8). Before the merger, each electric department employee within the three subsidiaries was responsible for 6,331 megawatthours of sales on average. By 1994, this average had increased by 12.7 percent to 7,137 megawatthours of sales, primarily due to sales growth and voluntary workforce reductions. However, by 1997, each electric department employee within the three utilities was responsible for 28,894 megawatthours of sales on average, a gain by a factor of four over the 1994 average. This gain was due to: (1) an increase in the volume of sales for resale after the merger due to the integration of, and open access to, the transmission systems of PSI Energy and CG&E, and increased competition in the wholesale market; (2) voluntary workforce reduction programs after the merger;[70] and, as noted above, (3) a shift in some of the utility department employees and their functions to CINergy Services after the merger.

Another measurement of employee efficiency is the average number of electricity customers served per electric department employee. Prior to the merger, the number of customers serviced per employee had increased from 159 in 1991 to 177 in 1994, or 11.3

[69] Some caution must be taken when drawing conclusions using electric department employee statistics after the merger, because it is likely that some of the functions that were performed by these employees prior to the merger, were transferred to the new subsidiary, CINergy Services, after the merger, and these employees are not counted as electric department employees. Thus, increases in employee efficiency may be overstated when using employee department statistics as a basis for measurement.

[70] CG&E and PSI completed another voluntary workforce reduction and severance program in 1996 that followed the one completed in 1994. Source: 1996 CINergy Corp. SEC 10-K, note 1 (l) to financial statements.

Figure C8. CINergy's Megawatthour Sales per Electric Utility Department Employee, 1991-1997



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

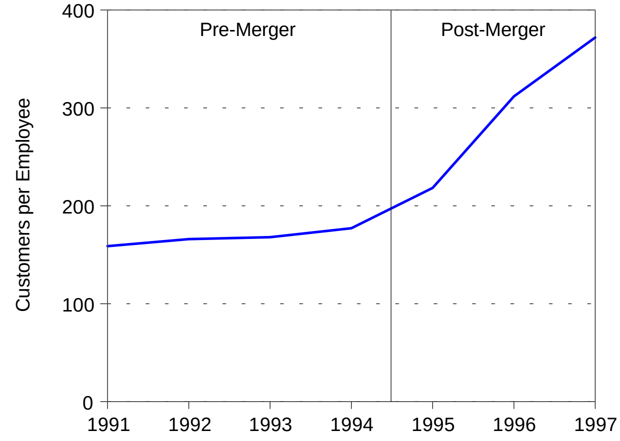
percent (Figure C9). After the merger, the average number of customers per electric department employee increased from 177 to 372, or 110 percent. This was due primarily to: (1) worker performance incentives;[71] (2) the voluntary workforce reduction program completed in 1996; and (3) the probable shift of some administrative positions to CINergy Services after the merger.

A customer-related measure of efficiency is customer expense per customer, adjusted for inflation. For this purpose, customer expense is defined as the sum of customer accounts expense and customer service and informational expenses. Real customer expense per customer decreased slightly before the merger, from $65.00 in 1991 to $61.00 per customer in 1994 (Figure C10). By the end of 1997, this measure had declined even further to $50.00 per customer, a savings of 18.0 percent from 1994 levels.

Overall Profitability Measurements

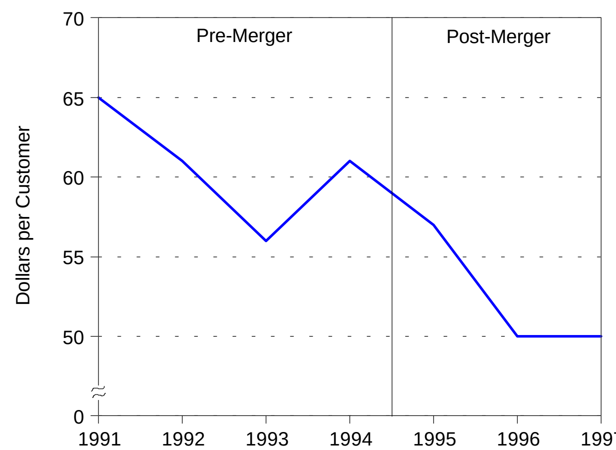
Net electric utility operating income for the sum of CINergy's three major utility subsidiaries peaked in 1995, the year after the closure of the merger, and each year through 1997 (Figure C11). Based on statements

Figure C9. CINergy's Electricity Customers per Electric Utility Department Employee, 1991-1997



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

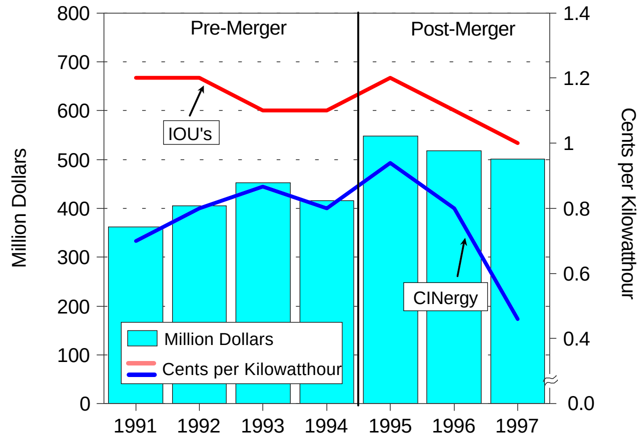
Figure C10. CINergy's Customer Expense, 1991-1997
(1997 Real Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries. Expenses include activities associated with supporting customer accounts, services, and information.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

[71] CINergy put into effect a new four-year cycle of its Performance Shares Plan on January 1, 1996, and implemented a new 1996 Long-Term Incentive Compensation Plan effective January 1, 1997. These more closely tie employee performance with cash and common stock ownership awards. Source: 1996 CINergy Corp. SEC 10-K, Footnote 2.

Figure C11. CINergy's Net Electric Utility Operating Income, 1991-1997
(Nominal Dollars)



Notes: Data represent the sum of CINergy's three major electric utility subsidiaries. IOU= Major investor-owned electric utilities.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

within CINergy's Annual Report for 1997, operating income declined for CINergy primarily for two reasons. First, the merger was good for only two to three years of earnings growth, and by 1997 merger-driven earnings growth had dissipated. Second, greater investment in CINergy's growth was needed after the merger for CINergy to meet its goal set at the end of 1996 of becoming the fifth largest combination electric and gas utility in the Nation within five years. This would be measured on January 1, 2002, on five dimensions: market capitalization, number of customers, gas and electric commodity trading, international markets, and productivity in key operational areas. The catchy phrase for this goal was "5 in 5 on 5." Movement toward this goal involved high costs for scaling up operations.[72]

Net utility operating income per kWh of total sales (retail and wholesale) for the period after the merger peaked in 1995 at 0.94 cents per kWh, and declined rapidly thereafter to 0.46 cents per kWh in 1997 (Figure C11).

In comparison, the net electric utility operating income per kWh for all IOUs also peaked in 1995, but at a higher level than CINergy at 1.17 cents per kWh. Thus, CINergy followed the Nation's decline in profit margins on total kWh sales after 1995 despite the benefits of the merger.

CINergy's decline in net utility operating income per kWh after 1995 is due to the reduction in total electric operating income evidenced in Figure C11 combined with the rapid increase in wholesale sales, as earlier shown in Figure C2. The increase in wholesale sales was derived from increases in wholesale customers, shown in Figure C3, due, in part, to CINergy's acceleration of power marketing and trading activity in the wholesale market. As part of the "5 in 5 on 5" goal, CINergy set out to expand trading / marketing activities to their fullest. As a result, by the end of 1997, CINergy ranked 7th in the Nation among electricity commodity trading companies, as measured by megawatthours purchased from power marketers. During 1997, CINergy was selected by the New York Mercantile Exchange (NYMEX) as one of only four electricity futures market trading hubs in the Nation. The trading hub was made operational in July 1998.[73]

CINergy's actual net earnings per average common share were higher in each year after the merger through 1997 as compared with 1994 levels, which might be expected based on the high level of savings derived from the merger. However, net earnings per share declined substantially in 1998 (Figure C12) because of "charges that resolve uncertainties and provide a more solid footing for future growth."[74] These charges included 0.54 cents per share in the energy marketing and trading business for the establishment of net trading liabilities. In contrast, CINergy, in its 1998 Annual Report, shows "normalized earnings" (adjusted for operational noncomparable items, nonoperational noncomparable items, and effects of weather) growing steadily from $1.85 per share in 1994 to $2.50 per share in 1998.

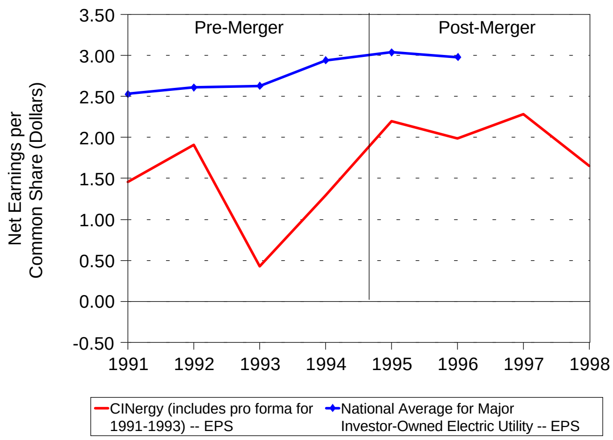
Investors clearly have shown that they liked CINergy's growth objectives, increasing the market share of its common stock faster than the Dow Jones Utility Average (Figure C13). Total returns on common stock equity (dividend yield plus capital appreciation of the stock) for each year after the merger through 1997 were substantial (Figure C14). From October 1994 through December 31, 1998, total return on common stock equity to CINergy's shareholders was 92.75 percent. But this total return was

[72] Op. cit., CINergy Corp. Annual Report for 1997, "Building Scale in 1997," and "Looking Outward to Increase Scale."

[73] Op. cit., CINergy Corp. Annual Report for 1997, "Key Performance Areas," and CINergy Corp. Annual Report for 1998, "Letter to Stakeholders."

[74] Op. cit., CINergy Corp. Annual Report for 1998, "Review of 1998."

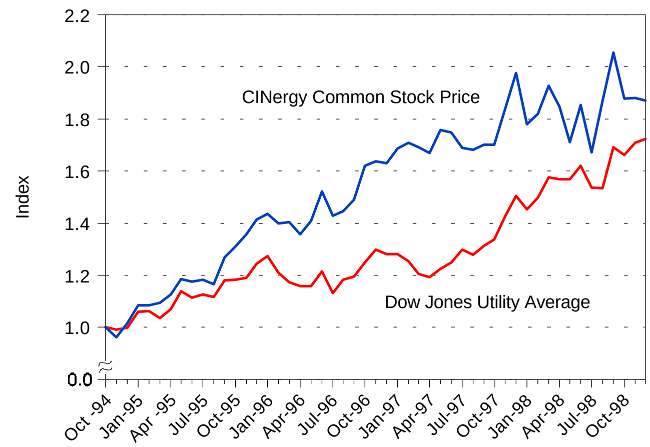
Figure C12. CINergy's and Major Investor-Owned Electric Utilities' Net Earnings per Average Common Share, 1991-1997



Note: Data represent the sum of CINergy's three major electric utility subsidiaries. National average for major IOU electric utilities unavailable for 1997 and 1998.

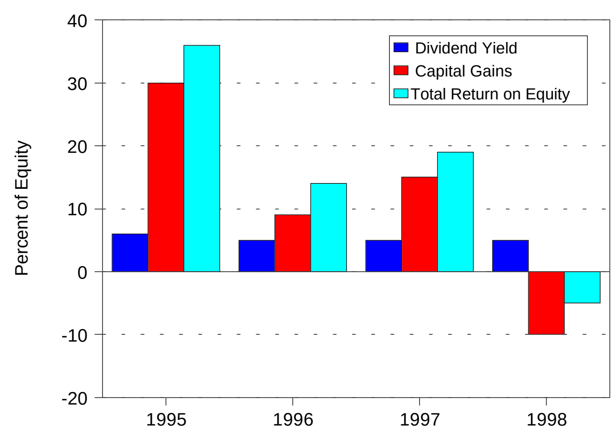
Source: Securities and Exchange Commission, Form 10-K, and Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities,* DOE/EIA-0437(91-96) (Washington, DC).

Figure C13. Comparison of CINergy Common Stock Price and Dow Jones Utility Average, October 1994 Through December 1998



Source: New York Stock Exchange and Dow Jones Reports.

Figure C14. CINergy's Total Return on Equity, 1995-1998



Source: Available on the Internet at http://yahoo.marketguide.com/mgi/performance/1897N.html.

below the average of a benchmark group consisting of the largest 25 electric utilities (98.19 percent) and below the average of the companies included in the Standard & Poor's (S&P's) electric index (100.74 percent). CINergy was above both of these comparable groups at the end of 1997, but experienced a negative total return in 1998 of 5.4 percent due to the 1998 drop in net earnings per common share cited above.[75]

One way to interpret CINergy's earnings and shareholder returns is that the shareholders truly gained from the merger, mainly because it led to high expectations in earnings growth, and led many investors to believe that CINergy would be one of the survivors in the industry when competition is fully implemented. Some of this earnings growth was actually realized in the 1994 to 1997 period, but by 1998, nearly all of the stimuli for earnings growth derived from the merger had been dissipated. By then, CINergy needed another major growth step in business operations in order to boost earnings and to maintain positive total annual returns on equity for the shareholders.

Assessment of Merger Effects on Ratepayers and Shareholders

Based on the overall growth, efficiency, and profitability measurements studied in this section, the following general conclusions can be drawn:

[75] Op. cit., CINergy Corp. Annual Report for 1998, "Letter to Stakeholders."

- The CINergy merger in 1994, when coupled with the opening of wholesale markets to competition in mid-1996, stimulated the rapid annual growth of electric operating revenues, wholesale kWh sales, and wholesale customers during the 1994 through 1997 post-merger period. In fact, growth in CINergy's business operations was the most noticeable result of the merger.

- CINergy's operational efficiency improved somewhat as a result of the merger. From 1994-1997, CINergy's real O&M costs per kWh declined faster than before the merger, its electric department workforce efficiency improved as measured by both megawatthour sales per employee and customers served per employee, and its real customer expense per customer declined. (Conclusions regarding electric department workforce efficiency gains have to be qualified because of the probable transfer of some electric department administrative functions to CINergy Services, the new subsidiary formed in 1994.)

- CINergy's ultimate (retail) customers enjoyed a slowdown in the growth of customer rates after the merger in nominal dollars (the 1.09 percent average annual increase in the 1991-1994 period dropped to 0.46 percent for the 1994-1997 period). However, adjusted for inflation, customer rates continued the same annual decline rate after the merger as before the merger (averaging 1.5 percent per year). Thus, retail ratepayers probably did not experience much real benefit from the merger. Wholesale customers did benefit by the integration of, and open access to, CINergy's transmission system.

- Shareholders of CINergy received the most direct benefit from the merger, at least through 1997. According to CINergy's 1998 Annual Report, shareholder total returns (dividends and common stock price gains) from merger closing through 1997 exceeded those for the S&P 500 electrics and a group of 25 of the largest combination electric and gas utilities. However, by the end of 1998, the impetus in growth of earnings and common share price from the merger had waned, and shareholders experienced a negative total return on common stock of 5.4 percent in 1998 due primarily to a downturn in operating income and net earnings per common share.

Analysis of Estimated Pre-Merger and Post-Merger Savings and Costs

As described previously, when CINergy first applied to the FERC for approval of the merger in 1992, it estimated that cost savings would be approximately $750 million over the 1994-2003 period. In 1993, CINergy increased its estimate to approximately $1.3 to $1.5 billion, but without providing many details. These cost savings were from elimination of redundant positions, deferred capital expenditures for generation, efficiency improvements in electricity production, and other improvements in the efficiency of administrative procedures. (See Table C1 for a summary of estimated pre-merger and post-merger cost savings.) Each of these potential cost savings categories are analyzed below, followed by an itemization of recorded merger costs.

Elimination of Redundant Employee Positions

CINergy initially estimated it was going to eliminate 400 employee positions made redundant by the merger, and increased the estimate to a range of 400 to 450, or about 10 to15 percent of "corporate" staff.[76] (PSI Energy and CG&E classified approximately 3,100 employees of 9,100 employees at the end of 1992 as "corporate staff.") These redundant position estimates were based on reduction ratios experienced by corporate departments in previous utility mergers and an analysis of employee efficiency ratios at comparable IOUs. These planned employee reductions were expected to lead to cost savings initially estimated at $229 million, and subsequently increased to a range of $296 to $331.9 million cumulative in the 1995-2003 period. CINergy based these estimates on an average salary in 1994 of $56,100, escalating at 4.5 percent per year in nominal dollars, and all employee reductions were phased in equally in three parts over the 1995-1997 period.

There is little doubt that the employee reductions occurred at least as well as planned. CINergy as a whole reduced its total number of employees by 1,259 (14.2 percent) over the 1994-1997 period, from 8,868 to 7,609. CINergy employees allocated to the electric departments at the three major subsidiaries declined by 3,753 (50 percent) over this same period, from 7,521 to 3,768. Some of these utility functions probably went to

[76] Op. cit., Prepared direct testimony of Lester P. Silverman, December 22, 1992, and Affidavit of Lester P. Silverman within Response of Applicants to Staff Request for Information, July 26, 1993.

Table C1. Cincinnati Gas & Electric Company/PSI Resources, Incorporated Pre-Merger Estimated Cost Savings Compared to Post-Merger Estimated Cost Savings
(Millions of Dollars)

Merger Savings Category	Pre-Merger Estimated Savings: 1st Estimate December 1992	Pre-Merger Estimated Savings: 2nd Estimate July 1993	Post-Merger Estimated Savings
Ten Year Savings			
1. Electricity production (including fuel savings and O&M costs)	113	281	281
2. Reduced revenue requirements due to capital expenditure reductions through deferral of new capacity	400	400	400
3. Administrative costs (elimination of approximately 400 redundant labor positions)	229	296-332	268[a]
4. Non-labor administrative savings (includes materials management, insurance premiums, software license fees, auditing and professional services, and management information systems)	–[b]	239-357	–[c]
5. Avoided capital expenditures not related to generation capital expenditures and production cost savings	–[d]	48	–[e]
Total Savings	**742**	**1,264-1,418**	**949**

Merger Costs Category	Cost Estimate Late 1994		Actual Cost 1994-1998
1. PSI Energy's transaction costs	27		
2. PSI costs to achieve merger savings	21		
Total PSI costs		48	
3. CG&E transaction costs and costs to achieve merger savings under the jurisdiction of the PUC	32		
4. Those costs not under the jurisdiction of the PUC	14		
Total CG&E (with Union) costs		46	
Total Costs		94	225

Net Merger Savings	Pre-Merger Estimated Net Savings	Post Merger Estimated Net Savings
Total Pre-Merger Estimated Savings (2nd estimate)	1,264-1,418	
(Less)Total Pre-Merger Estimated Costs	94	
Estimated Net Merger Savings	1,170-1,324	
Total Post-Merger Savings Estimate		949
(Less)Total Post-Merger Actual Costs		225
Net Merger Savings		724

[a] What cannot be determined from this analysis is the level of salaries and wages within CINergy Services that, prior to the reorganization in 1994, were properly attributed to the electric departments of CINergy's three major utility subsidiaries. This means that the total savings shown are probably overstated but are within the broad range of $229 – 332 million.

[b] Initially non-costed.

[c] There was no evidence that could be drawn from the Federal Energy Regulatory Commission's (FERC's) Form 1 data, for the years 1994 through 1997, that CINergy's non-labor administrative cost merger savings would be realized.

[d] Initially non-costed.

[e] Because this figure was not itemized in the estimate provided to FERC, publicly available data could not be applied to determine whether or not these capital expenditures were actually avoided.

Sources: Pre-Merger Savings: Federal Energy Regulatory Commission, Cincinnati G&E/PSI Merger Application; Post-Merger Savings: Federal Energy Regulatory Commission, Form-1; Pre-Merger Cost Estimate: Securities and Exchange Commission 10-K Filing, 1994; Post- Merger Actual Cost: Securities and Exchange Commission 10-K Filings 1994-1998.

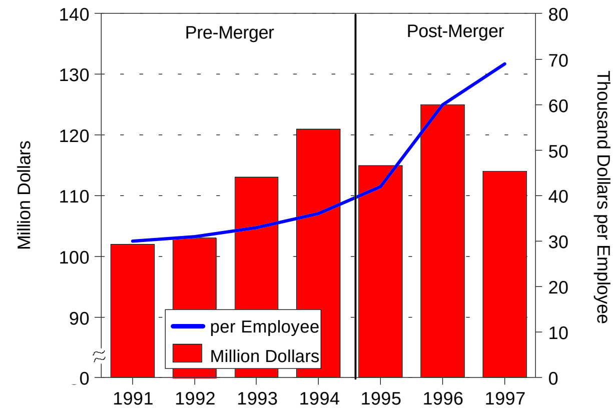
CINergy Services, Inc. But, since the whole company's total staff declined by about three times more than estimated, one can conclude that the employee reductions resulting from the merger were probably realized.

Another question is whether the dollar savings from employee reductions were realized. Total "corporate employee" salaries and wages fell by 0.6 percent during the 1994-1997 period, as compared to a rise of 14.1 percent over this period as initially projected by the CINergy applicants (i.e., 4.5 percent annual growth rate in salaries and wages applied over three years) (Figure C15).[77] The savings from the reduction in salaries and wages accumulate to approximately $41 million over the period. Applying the reported average overhead rate of 30 percent for benefits and pensions yields a total salaries and benefits savings of approximately $53 million. When the savings are projected out from 1997 at the labor cost inflation rate used by CINergy of 4.5 percent per year, total salaries and benefits savings accrue to approximately 268 million in nominal dollars for the 10-year period 1994-2003. (Table C2 displays the worksheet used to project salaries and benefits savings.)

What cannot be determined from this analysis is the level of salaries and wages within CINergy Services that, prior to the reorganization in 1994, were properly attributed to the electric departments of CINergy's three major utility subsidiaries. This means that the total savings shown are probably overstated. However, with this qualification, it appears that public data support CINergy's estimate of savings due to the elimination of redundant employee positions within the broad range of $229 to $331.9 million.

What is surprising is that realized savings are close to estimated savings when the workforce within the electric departments of the three subsidiaries was actually reduced by 3,753 employees, which was far greater than the 400-450 positions estimated by CINergy, implying that the savings should have been higher than originally estimated. Figure C15 provides an understanding of what happened. Total wages and salaries per electric utility employee (including production, transmission, and distribution employees) grew at a rate of 24.2

Figure C15. CINergy's Total Salaries and Wages of Corporate Employees, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

percent per year in the 1994-1997 period, much higher than CINergy's projected average annual labor inflation rate of 4.5 percent. This was probably a direct result of: (1) CINergy's post-merger recruitment program aimed at attracting and retaining people talented in trading, marketing, and other competitive areas, in contrast to traditional utility functions;[78] and (2) CINergy's new employee incentive programs which provided cash as well as common stock bonuses based on performance.

Savings From Deferral of Generation Capacity

The merging entities projected that coordination of the dispatch of their generation plants would result in an ability to cut their planning reserve margin[79] from 20 percent or more, to 17 percent. This allowed a deferral of constructing approximately 499 MW of new generation capacity over the 1995-2003 period. This included one 120 turbo power and marine combustion turbine

[77] A corporate employee is defined here has any employee associated with salaries and wages not allocated to the production, transmission, and distribution functions. When CINergy made its employee reduction projection, it did specify the level of reduction by department, but this could not be compared directly with the FERC Form 1 data.

[78] In op. cit., CINergy Corp. Annual Report for 1997, "Letter to Stakeholders; Expanding our Capabilities and Soul," CINergy noted that it is trying to develop the mentality of the new entrant, and the mentality of the trader in its corporate culture, partly through recruiting.

[79] See Footnote No. 48 for the definition of planning reserve margin.

Table C2. CINergy's Estimated Post-Merger Savings in Corporate Salaries and Benefits
(Thousand Dollars Nominal)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Projected Salaries and Wages at 4.5% per year from 1994	120,558	125,983	131,652	137,577	143,768	150,237	156,998	164,063	171,446	179,161	1,481,442
Actual Salaries and Wages through 1997 . . .	120,558	115,066	125,329	114,041		--	--	--	--	--	474,994
Projected Salaries and Wages 1998-2003 at 4.5% per year from 1997	–	–	–	–	119,173	124,536	130,140	135,996	142,116	148,511	800,471
Savings in Salaries and Wages	--	10,917	6,323	23,536	24,595	25,702	26,858	28,067	29,330	30,650	205,977
Savings in Benefits and Pensions at 30% of Salaries and Wages	--	3,275	1,897	7,061	7,378	7,710	8,057	8,420	8,799	9,195	61,793
Total Corporate Employee Savings	--	14,192	8,220	30,596	31,973	33,412	34,916	36,487	38,129	39,844	267,770

-- = Not applicable.

Notes: The 4.5 percent escalation rate is the same as used by Lester P. Silverman in his prepared testimony before FERC. The rate of 30 percent of salaries and wages for pensions and benefits was estimated by taking total 1995 FERC Form 1 employee benefits and pensions and dividing by total wages and salaries. Actual Salaries and Wages through 1997 are taken from FERC Form 1.

(CT) scheduled for 1995 by PSI, and one 400 MW coal baseload plant planned by CG&E for 2002. Larger CTs would be substituted for the CTs planned by PSI over the 1999-2003 period. In fact, the merger would allow CINergy to defer all baseload capacity additions until 2004 or beyond. Whereas the two generation systems operating independently would require 1,690 MW of capacity additions over the 1995-2003 period, CINergy would only require 1,191 MW. These deferrals were projected to result in a reduction of fixed charges of $400 million over the 1995-2003 period.[80]

To determine whether these savings are being realized, one can inspect the capacity additions that actually occurred over the 1995-1998 period. The difference was expected to be the deferral of one 99 turbo power and marine CT in 1995 on the PSI system. Also, instead of three Asea Brown Boveri CTs amounting to 231 MW planned for the CG&E system in 1998, CINergy would be adding somewhere on its system only one 99 MW turbo power and marine CT. Deferred fixed charges to rates were projected to be $7.5 million in each of years 1995-1997, and $19.8 million in 1998, accumulating to $42.3 million over the 1995-1998 period.[81] These merger savings were in fact realized because, according to CINergy's filed SEC 10-K reports for the corresponding years, CINergy added no new generation capacity over the 1995-1998 period. Instead, 129 MW of oil generation capacity at the Miami Fort Gas Turbine Station in North Bend, Ohio was eliminated over this period.

CG&E testified before the FERC in the initial merger application, that it took approximately four years of lead time to bring new CT capacity on line and 10 years for new coal-fired base load capacity.[82] Within its 1996 SEC Form 10-K, CINergy stated that it is no longer forecasting investments in new generating facilities under the belief that excess supply in the market will continue to exist at least through the transition to full retail competition. CINergy presented no capital investment plans for new generation capacity in the 1999-2003 period. Thus, it is likely that the entire $400 million in initially estimated reduced revenue requirements associated with deferred generation capacity additions will be realized over the 1995-2003 period.

Electricity Production Cost Savings

The merging entities initially estimated in December 1992 production cost savings of $113 million over the 1994-2003 period, and in 1993, increased this estimate to

[80] The source of the generation capacity deferral estimates and associated savings is the Prepared Direct Testimony of James E. Benning, Vice President, Power Operations of PSI Energy, Inc., December 21, 1992.

[81] Op. cit., Testimony of James E. Benning, December 21, 1992.

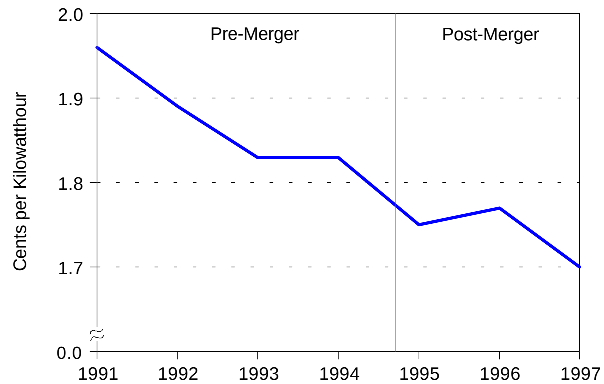
[82] Source: Prepared Direct Testimony of Terry E. Bruck, Vice President, Electric Operations, The Cincinnati Gas & Electric Company, before the Federal Energy Regulatory Commission, Docket No. EC93-6, December 18, 1992.

approximately $281 million.[83] Electricity production cost savings included both O&M cost savings and fuel cost savings that resulted from the coordinated dispatch of the generation units to meet the electricity requirements of retail consumers and firm contract wholesale customers. Under the initial estimate, the savings were small in the early years, totaling $25 million from the closure of the merger through 1997 (Table C3). No annual details for the second estimate were provided to the FERC, but the simple scaling up of the $25 million initial estimate by the ratio of the two total production cost estimates yields a second estimate of $62 million in savings for the 1994-1997 period.

This category of savings is difficult to assess using publicly available data because CINergy's projection of production costs savings is based on the execution of an electric power dispatch model, PROMOD III, and very few of the many assumptions used to run the model were discussed in CINergy's application to FERC. However, using FERC Form 1 data, one can obtain an estimate of these savings by observing changes during the 1994-1997 period in power production costs associated with generation. This can be approximated by subtracting purchased power expenses from total power production costs.

The data suggest that the merging entities were becoming more efficient even before closure of the merger, as this measure of average native load power production costs decreased from 1.96 cents per kWh to 1.83 cents per kWh between 1991 and 1994, a decline of 6.4 percent (Figure C16). However, after the merger, the efficiency gains accelerated, and by 1997, total power production costs minus purchased power expenses per net generation kilowatthour dropped to 1.70 cents per kWh, a decline of 7.4 percent from the 1994 level.

Figure C16. CINergy's Power Production Expenses, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Because the fuel price escalation assumptions underlying CINergy's PROMOD III model runs are unknown, apparent efficiency gains due to differences in actual and assumed fuel price escalation cannot be isolated from efficiency gains due to the coordination of generation dispatch. Therefore, the best available comparison with

Table C3. Post-Merger Production Cost Savings For CINergy Corporation

	1993	1994	1995	1996	1997	Total
Actual Total Production Costs Minus Purchased Power Expenses per Net Generation kWh (c/kWh)	1.8338	1.8320	1.7506	1.7666	1.6961	--
Savings per kWh from 1993 (c/kWh)	--	0.0018	0.0832	0.0672	0.1377	--
Total Retail Sales and Wholesale Sales (MWh)	--	47,619,873	49,977,949	51,409,473	51,708,202	--
Estimated Actual Production Cost Savings (Million Dollars)	--	0.9	41.6	34.5	71.2	148.2
CINergy Initially Projected Production Cost Savings (Million Dollars)	--	7.0	3.0	3.0	12.0	25.0

-- = Not applicable.
Note 1: Source of Actual Data on Production Costs, Generation and Sales is FERC Form 1.
Note 2: Source of CINergy Initially Projected Production Cost Savings is Prepared Testimony of James E. Benning, FERC Docket No. EC93-6, December 21, 1992, Exhibit JEB-13.

[83] Op. cit., Prepared Direct Testimony of James E. Benning, December 21, 1992, and Affidavit of James E. Benning, July 26, 1993, before the Federal Energy Regulatory Commission, Docket No. EC93-6.

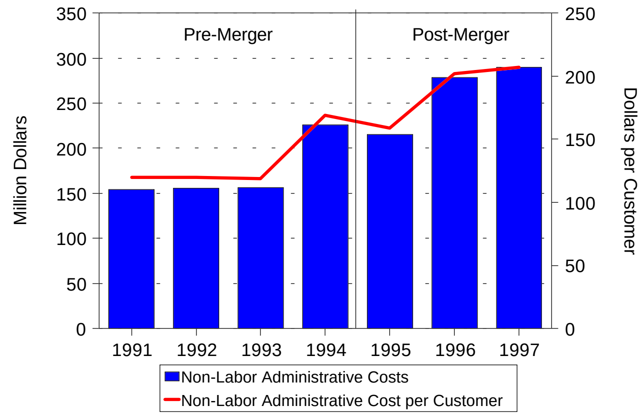
CINergy's projected production cost savings estimate is obtained by assuming that the entire decline in total power production costs minus purchased power expenses per net generation kilowatthour from 1994 to 1997 is due to efficiency gains from the coordination of generation dispatch. This produces a total estimated production cost savings of approximately $148 million through 1997 (Table C3). This apparent savings is far greater than the high estimate of $68 million for the 1994-1997 period as derived above from CINergy's second estimate of production cost savings. Thus, it is probable that CINergy attained at least its high estimate in production cost savings over the years 1994-1997. Furthermore, because CINergy did not actually add more generation capacity than expected at the time of the merger application, and generation dispatch will continue to be coordinated by the merged entities, it is likely that production cost savings will continue to accrue in the 1998-2003 period as estimated by CINergy utilizing the PROMOD III model. In conclusion, inferences that can be drawn from the FERC Form 1 data appear to support CINergy's high estimate of $281 million in production cost savings over the 1994-2003 period.

Other Administrative Cost and Capital Expenditure Savings

In the initial estimate of merger savings by the applicants (December 1992), non-labor cost savings were not estimated. They were expected to be derived from materials management savings, insurance premium savings, savings on software license fees, auditing and professional services, and lower capital expenditures on management information systems.[84] For the second estimate that was submitted to the FERC in July 1993, non-labor administrative cost savings were estimated at $239 to $357 million over the 1994-2003 period, and avoided capital expenditure savings (not related to generation capital expenditures and production cost savings) were estimated at $48.4 million. However, no details were provided to the FERC.[85]

An inspection of non-labor administrative cost efficiency changes after the merger may provide a clue as to whether CINergy's estimated non-labor administrative cost savings are being realized. Figure C17 shows annual changes for a proxy from the FERC Form 1 data for non-labor administrative costs minus allocated salaries and wages. The costs are the sum of total customer accounts expenses, total customer service and information

Figure C17. CINergy's Non-Labor Administrative Costs, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of CINergy's three major electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

expenses, total sales expenses, and administrative and general expenses. Non-labor administrative costs for the three utility subsidiaries held reasonably steady at approximately $150 million over the 1991-1993 period, then increased dramatically with the reorganization in 1994 to over $225 million. In the post-merger period, non-labor administrative costs increased further to over $290 million by 1997. When these non-labor administrative expenses are divided by total customers as shown in Figure C17, efficiency gains after the merger are still not apparent. In fact, non-labor administrative costs increased from about $169 per customer in 1994 to over $207 per customer in 1997.

Based on these illustrations, it can be concluded that the FERC Form 1 data does not support the realization of CINergy's estimated non-labor administrative cost savings in the post-merger period through 1997. Because the estimated avoided capital expenditure savings of $48.4 million in CINergy's second estimate were not itemized before the FERC, publicly available data could not be applied to determine whether or not these capital expenditures were actually avoided.

Merger Costs

At the end of 1994, total merger costs over the 1994-2003 period were estimated to be $48 million for PSI Energy,

[84] Op. cit., Prepared Direct Testimony of Lester P. Silverman, December 22, 1992, pages 19 and 20.
[85] Op. cit., Response of Applicants to Staff Request for Information, July 26, 1993, page 3.

at least $46 million for CG&E, and therefore at least $94 million for CINergy as a whole. However, actual costs attributed to the merger shown on CINergy's SEC 10-K annual reports for the years 1994 through 1998 totaled about $225 million (Table C4).

In 1994, CINergy recognized charges to earnings of approximately $79 million for merger costs and other costs which they could not recover from customers due to rate settlements related to securing support for the merger. This included: (1) the PUCO electric jurisdictional portion of merger transaction costs and costs to achieve merger savings incurred through December 31, 1994 ($32 million); (2) previously capitalized information systems development costs; and (3) severance benefits to former officers of CG&E and PSI Energy. In 1995, CG&E expensed another $5 million in merger costs allocable to PUCO jurisdictional customers.

Beginning on October 1, 1996, PSI began expensing approximately $40 million of deferred merger costs over 10 years. Thus, approximately $1 million of this accrual was expensed in 1996. PSI also expensed $5 million for another set of voluntary workforce reduction and severance programs. CG&E expensed another $41 million allocable to PUCO jurisdictional customers, including $30 million for the second set of voluntary workforce reduction and severance programs. Thus, the total expensed in 1996 for CINergy was approximately $47 million.

In 1997 and 1998, PSI expensed approximately $4 million per year in deferred merger costs. Thus, from 1994 through 1998, approximately $140 million in merger-related costs had been written off, and $85 million in deferred merger costs were still on the books for future recovery from ratepayers, yielding a total for actual merger-related costs of $225 million.

Assessment of Realized Merger Costs and Savings

The following conclusions can be drawn from the above comparison of publicly available data on CINergy's merger savings and costs with estimates made available by CINergy during the merger approval process:

- CINergy's voluntary manpower reduction programs completed in 1994 and 1996 probably achieved the planned elimination of at least 400 to 450 positions associated with electric utility activities. Apparent related savings in salaries and benefits is estimated at $268 million based on available FERC Form 1 data. This estimate based on publicly available data through 1997 falls near the middle of the range provided by CINergy's first and second estimates of $229 to $331.9 million, respectively.

- The entire $400 million in CINergy's estimated merger savings from the deferral of the construction of new generation capacity will likely be realized. CINergy has not constructed and does not appear to be planning to construct more generation plant capacity than planned during the merger process, based on data available with CINergy's SEC 10-K reports for the years 1994 through 1998.

- Inferences that can be drawn from FERC Form 1 data appear to support the realization of CINergy's high estimate of $281 million in production cost savings over the 1994-2003 period.

Table C4. Actual Accrued and Expensed Merger Pre-Tax Costs of CINergy Corporation
(Dollars in Millions Nominal)

	1994	1995	1996	1997	1998	Total
Accrued Merger Costs End of Current Year	50.0	57.0	94.0	90.0	85.0	--
Accrued Merger Costs End of Previous Year	NA	50.0	57.0	94.0	90.0	--
Increase (Decrease) in Accrued Merger Costs	50.0	7.0	37.0	(4.0)	(5.0)	85.0
Expensed Merger-Related Costs	79.0	5.0	47.0	4.0	5.0	140.0
Total Net Accrued and Expensed Merger Costs	129.0	12.0	84.0	0.0	0.0	225.0

NA = Not available.
-- = Not applicable.
Source: CINergy Corporation SEC 10-K for corresponding years.

- There was no evidence that could be drawn from the FERC Form 1 data, for the years 1994 through 1997, that CINergy non-labor administrative cost merger savings, estimated between $239 and $357 million over the post-merger 10-year period, would be realized. This category of savings was not costed in CINergy's first estimate of merger savings.

- CINergy provided FERC with no details related to estimated avoided capital expenditures nor to generation or production costs, amounting to $48.4 million over the decade beginning in 1994. As a result, publicly available data could not be applied to assess whether any of this category of merger savings was being realized in the 1994-1997 period.

- Merger-related costs shown on CINergy's SEC 10-K reports for the years 1994 through 1998 amounted to $225 million.

- Estimated gross merger cost savings are approximately $949 million ($268 million associated with workforce reductions; $400 million due to deferred construction of new generation capacity; and $281 million in production cost savings). All merger-related costs already appearing on CINergy's financial statements amount to $225 million. Therefore, the best estimate of net merger savings over the 1994-2003 period that can be drawn from publicly available data is $724 million. This compares somewhat well to the $949 million estimate prior to the merger.

Appendix D

1993 Merger of Gulf States Utilities Company into Entergy Corporation

Appendix D
Case Study[86]

1993 Merger of Gulf States Utilities Company into Entergy Corporation

In 1993, Gulf States Utilities Company (Gulf States or GSU) merged with Entergy Corporation (Entergy) to form a new registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA), also called Entergy Corporation. The focus of this analysis is to determine, using public data, if the objectives of the merger were realized. The objectives of the merger were: (1) to save $1.7 billion in costs from 1994 through 2003; (2) to provide shareholders more attractive earnings prospects due to a financially and operationally stronger, combined company that is strategically positioned for additional growth and increased market recognition; (3) to provide GSU's customers lower electricity rates due to lower fuel costs and a 5-year cap on base electric rates; (4) to provide all other Entergy customers lower costs of service and lower customer rates due to reduced operations and maintenance (O&M) expenses and capacity deferral savings,[87, 88] and (5) to help GSU alleviate operational and financial problems brought on, in part, by rate base disallowances for nuclear plant construction costs.[89]

Data sources for this case study were (1) the Federal Energy Regulatory Commission (FERC): Merger application and testimony, and FERC Form-1, (2) the Securities and Exchange Commission (SEC): 10K filings, and (3) annual reports of the merging companies.

Description of the Companies

The merger of Entergy Corporation, a Florida corporation, with GSU, a Texas corporation, actually consisted of interim corporate mergers resulting in a new holding company, named Entergy Corporation, a Delaware corporation. After the merger, GSU became a wholly-owned subsidiary of the new Entergy Corporation. The acquisition of GSU was consummated on December 31, 1993, shortly after obtaining approval of the merger by the FERC on December 15, 1993 (Order/Opinion No. 385), and two days after receiving final approval from the Public Utility Commission of Texas.

Entergy Corporation (Pre-Merger)

Prior to the merger, Entergy Corporation was incorporated in Florida in 1949, and was a holding company under PUHCA. Entergy owned all the common stock of four major electric utilities: Arkansas Power and Light Company (AP&L), Louisiana Power & Light Company (LP&L), Mississippi Power & Light Company (MP&L), and New Orleans Public Service, Incorporated (NOPSI).[90] These four retail utilities provided electricity to 1.7 million ultimate consumers located within the States of Arkansas, Missouri, Louisiana, Mississippi,

[86] This case study was adapted from a report prepared under contract to the Energy Information Administration, U.S. Department of Energy.

[87] Source: Prepared direct testimony of Edwin Lupberger, Chairman and CEO of Entergy Corporation, before the Federal Energy Regulatory Commission, Docket No. EC92-21-000, August 21, 1992.

[88] These reasons were further elaborated upon by Mr. Donald Hunter, Senior Vice President of Entergy Corporation, in his Prepared Direct Testimony before the Federal Energy Regulatory Commission, Docket No. EC92-21-000, August 19, 1992.

[89] Source: Prepared Direct Testimony of Joseph L. Donnelly, Chairman, President and CEO of Gulf States Utilities Company, before the Federal Energy Regulatory Commission, Docket No. EC92-21-000, August 19, 1992.

[90] The term "major utility" is used here to denote a major utility for reporting purposes under FERC Form 1, the primary source of data used as a basis for this merger analysis. Under FERC Form 1, a major utility had, in each of the last three consecutive years, sales or transmission service that exceeded one of the following: (1) one million megawatthours of total annual sales; (2) 100 megawatthours of annual sales for resale; (3) 500 megawatthours of annual power exchanges delivered; or (4) 500 megawatthours of annual wheeling for others (deliveries plus losses).

Mississippi and Louisiana, and to 23 wholesale customers. In addition, NOPSI provided gas service to 154,251 customers within the City of New Orleans.[91]

At the time of the merger, Entergy Corporation owned all the common stock of another major utility, System Energy Resources, Inc. (System Energy). System Energy owned 90 percent of Grand Gulf 1 (a nuclear power plant), and sold all of the plant's electricity at wholesale to Entergy's four retail utilities.

In addition, Entergy Corporation owned four other nonutility subsidiaries: Entergy Services, Inc., Entergy Operations, Inc., Entergy Power, Inc., and Entergy Enterprises, Inc. Entergy Services provided general executive and advisory services, and accounting, engineering, and other technical services to certain of the Entergy Corporation subsidiaries, generally at cost. Entergy Operations is a nuclear management company that operated all the nuclear facilities on the Entergy System,[92] subject to the owner oversight of AP&L, GSU, LP&L, and System Energy. Entergy Power is an independent power producer that owned 809 MW of generating capacity at the close of 1993, and marketed its capacity and energy in the wholesale markets not otherwise presently served by the Entergy System. Entergy Enterprises was utilized to invest in businesses whose products and activities were of benefit to the Entergy System's utility businesses, and to market technical expertise developed by the Entergy System companies when it was not required for the operations of the Entergy System.

In addition to Entergy's nonutility subsidiaries, the four retail electric utility subsidiaries jointly owned System Fuels, Incorporated, a non-profit subsidiary that implemented and / or maintained programs to procure, deliver and store fuel supplies for the Entergy System. As early as the close of 1993, Entergy Corporation and its various subsidiaries (including those which are not wholly-owned by Entergy Corporation itself and are not described above) also had a variety of investments in non-regulated businesses associated with overseas power development and new electro-technologies. Entergy was also seeking at the end of 1993 to provide telecommunications services based on its experience with interactive communications systems that allow customers to control energy usage.[93]

Gulf States Utilities Company: Gulf States Utilities Company (GSU) was incorporated in Texas in 1925. At the end of 1993, GSU served approximately 593,000 retail electricity customers in Texas and Louisiana, and 85,000 natural gas customers in the Baton Rouge, Louisiana area. As such, GSU had about one-third the number of electricity customers as did Entergy Corporation prior to the merger, but total assets were about 46 percent of Entergy's. GSU's steam products department also produced and sold, on an unregulated basis, process steam and by-product electricity from its steam electric extraction plant to a large industrial customer.

GSU had four wholly-owned subsidiaries at the end of 1993: Varibus Corporation, GSG&T, Inc., Southern Gulf Railway Company, and Prudential Oil & Gas, Inc. Varibus Corporation operated intrastate gas pipelines in Louisiana, used primarily to transport fuel to two of GSU's generating stations. Varibus Corporation also marketed computer-aided engineering and drafting technologies and related computer equipment and services. GSG&T, Inc. owned a gas-fired generating plant that is leased and operated by GSU. Southern Gulf Railway Company was formed to own and operate several miles of rail track being constructed at the end of 1993 in Louisiana for the purpose of transporting coal for use by one of GSU's generating plants. Prudential Oil & Gas, Inc., an oil and gas exploration company, was inactive at the end of 1993.

Entergy Corporation (Post-Merger Entergy)

A new holding company, originally named Entergy-GSU Holdings, Inc. and later renamed Entergy Corporation, was formed from the merger. All of the wholly-owned subsidiaries of the predecessor Entergy Corporation became wholly-owned subsidiaries of the new Entergy

[91] Source: 1993 SEC 10-K report for Entergy Corporation, "Selected Data."

[92] The term "Entergy System" is used in this report to denote Entergy Corporation and its various direct and indirect subsidiaries. It is the same term as used by Entergy Corporation in its 1993 SEC 10-K report, which is the source of the descriptions of the various subsidiaries of Entergy Corporation as presented in this section.

[93] Source: 1993 SEC 10-K report for Entergy Corporation, "Corporate Development." This provides a detailed description of several other subsidiaries of Entergy Corporation and its wholly-owned subsidiaries, which are involved in pursuing and overseeing Entergy investments in the broad areas of overseas power development and new electro-technologies. These include: a 60-percent interest in Argentina's Costanera steam electric generating facility; a 5-percent interest in an electric distribution company providing service to Buenos Aires, Argentina; a 65-percent interest in a transmission system in Argentina; a 9.95-percent interest in First Pacific Networks, Inc, a communications company, along with joint development of a license for utility applications; and a 50-percent interest in an independent power plant in Richmond, Virginia.

Corporation. As a consideration to GSU's shareholders, Entergy Corporation paid $250 million in cash and issued 56,667,726 shares of its common stock at a price of $35.8417 per share, in exchange for outstanding shares of GSU common stock. This amounts to a total capital cost of approximately $2.3 billion for GSU. GSU also became a wholly-owned subsidiary of the new Entergy Corporation and thereby became the fifth major retail operating utility of Entergy.

After the merger, Entergy Corporation was the second largest electric utility in the Nation. When the six major utilities are combined, the new Entergy Corporation had 2.3 million electric customers, $23.6 billion in total assets and $6.7 billion in total utility operating revenues. When all other regulated and non-regulated subsidiaries are also taken into account, the newly formed Entergy had $22.9 billion in assets, $6.27 billion in total utility operating revenues ($6.14 billion electric, $0.12 billion gas), $631 million in net income, and 16,679 employees.[94]

Pre-Merger Estimated Savings and Costs of the Merger

The merging entities estimated cost savings of $539 million over the first five years (1994-1998) of the merger, and approximately $1.7 billion over the first 10 years (1994-2003).[95] These savings were expected from: (1) $274 million over the first five years ($849 million over the first 10 years) due to fuel savings achieved by combining the two fuel purchasing systems and coordinating generation dispatch;[96] (2) $265 million over the first five years ($673 million over the first 10 years) due to nonfuel O&M cost reductions resulting primarily from Entergy taking over the operation of GSU's nuclear generation plant and the streamlining of GSU's steam production, administrative, and customer support activities; and (3) $184 million during the last five years of the decade following the merger (1999-2003) due to deferral of resource capacity additions on Entergy's system made possible because of the coordination of the dispatch of Entergy's and GSU's generation systems.

Of the estimated $539 million in savings over the first five years, GSU would receive $515 million. Of the estimated $1.7 billion in merger savings over the first 10 years, GSU would receive $1.43 billion. The $184 million associated with deferral of capacity additions represented the greatest potential source of cost savings for Entergy. Without the merger, on a stand-alone basis, the Entergy system would have incurred a resource capacity deficit in 1999; GSU not until 2006. The combined Entergy and GSU system was projected to show a resource capacity deficit not until the year 2001, and a smaller resource capacity deficit than that for Entergy as a stand-alone system. Thus, Entergy is the benefactor of all the savings associated with capacity deferrals in the 1999-2003 period. Combining these savings with approximately $95 million in nonfuel O&M cost reductions for Entergy, $59 million in fuel savings due to generation dispatch coordination, and netting out Entergy's additional costs associated with System Agreement synergies, Entergy's share of total merger savings over the 10-year period was estimated at approximately $260 million.

Merger costs consist of both merger transaction costs and costs to achieve merger savings. These included: (1) one-time capital costs of $37 million, incurred over the first three years after the merger, to add or modify facilities and equipment at GSU's River Bend nuclear plant; (2) one-time capital costs of $28 million, incurred over the first four years after the merger, to conform GSU fossil steam generation equipment to Entergy specifications; and (3) one-time O&M expenditures of $12.4 million for the implementation of an early retirement program and directors' and officers' insurance premiums in order to facilitate workforce reductions and administrative cost savings.[97] Although not specified at the time of the merger application before the FERC, merger transaction costs were known by the close of the merger to be $33.5 million, as accounted for in Entergy's SEC 10-K report for 1993. Thus, by the close of the merger, total estimated merger costs were approximately $111 million.

[94] Source: 1993 SEC 10-K report for Entergy Corporation, "Selected Data."

[95] Op. cit., Prepared direct testimony of Donald Hunter for nonfuel O&M merger savings estimates and Prepared Direct Testimony of Frank F. Gallaher for production cost savings (including) fuel cost savings, and capacity deferrals resulting from the merger. These announced merger savings were exclusive of the $12.4 million in estimated 1994 O&M costs associated with early retirement expense and severance pay.

[96] The joint dispatch of electric generation plants allows the next lowest operating cost plant chosen among all generation plants of the merged entities to be the next plant brought on line to meet demand. The result is lower electricity production costs than the two firms would incur when acting separately to meet the same aggregate electricity demand, because each firm would be choosing the next lowest cost plant for dispatch only from its own, more limited set of generation plants.

[97] Op. cit., Prepared Direct Testimony of Donald Hunter, pages 25 through 42.

Allocation of Merger Costs and Savings to Customers and Shareholders

Each State regulatory commission provided formulas for allocating merger costs and savings between ratepayers and shareholders. These allocation formulas are worth noting because they may demonstrate the effects of the merger on electricity rates and shareholder returns on equity. The settlement agreement regarding the allocation formulas is usually complex, and therefore, only the highlights of the formula are discussed.[98]

The Louisiana Public Service Commission (LPSC) and the Public Utility Commission of Texas (PUCT) each approved separate regulatory proposals that included a five-year rate cap on GSU's retail electric base rates in the respective States, and provisions for passing through to retail customers in the respective States the jurisdictional portion of the GSU fuel savings created by the merger. The LPSC plan provided that nonfuel merger savings will be shared 60 percent by the shareholder and 40 percent by the ratepayers during the eight years following the merger. The PUCT plan provided that such savings will be shared equally by the shareholder and ratepayers, except that the shareholder's portion will be reduced by $2.6 million per year on a total company basis in years four through eight.

AP&L, MP&L and NOPSI entered into separate settlement agreements, approved by their respective State regulatory commissions, whereby their retail customers would be protected from: (1) increases in the cost of capital resulting from risks associated with the merger; (2) recovery of any portion of the acquisition premium or transactional costs associated with the merger; (3) certain direct allocations of costs associated with GSU's River Bend nuclear plant, and (4) any losses of GSU resulting from resolution of litigation in connection with its ownership of the River Bend nuclear plant.

In connection with the merger, AP&L agreed that it would not request any general rate increase that would take effect before November 3, 1998, with certain exceptions. MP&L agreed that retail base rates would not be increased for a five-year period above the level in effect as of November 1, 1993. NOPSI agreed to reduce base rates by $4.8 million on November 1, 1993 and to freeze base rates until October 31, 1996, with certain exceptions.

In connection with the merger, the FERC approved certain rate schedule changes to integrate GSU into the System Agreement, which provides for the coordination of planning, construction, and operation of Entergy's generation and transmission facilities. The FERC also required cost-tracking mechanisms and other commitments to provide reasonable assurance that the ratepayers of the existing Entergy operating companies before the merger, would not be allocated higher costs.

Merger savings associated with fuel costs would normally be recovered entirely by the ratepayers through the exercise of fuel adjustment clauses approved by the various regulatory agencies.[99]

Effects of the Merger on Entergy's Growth, Efficiency, and Profits

As stated previously, one objective of the merger was to achieve cost savings from improved efficiency in operations and administration, and thereby to increase returns to equity shareholders and reduce rates to customers. Another objective was to place the merged company in a better strategic position for growth and profitability. Success in achieving this latter objective can be measured by comparing growth of electric revenues, sales, and income before and after the merger.

Overall Growth Measurements

Entergy enjoyed rapid growth in electric operating revenues before the merger (1991-1993) at 5.8 percent annually, but after the merger (1993-1997), annual

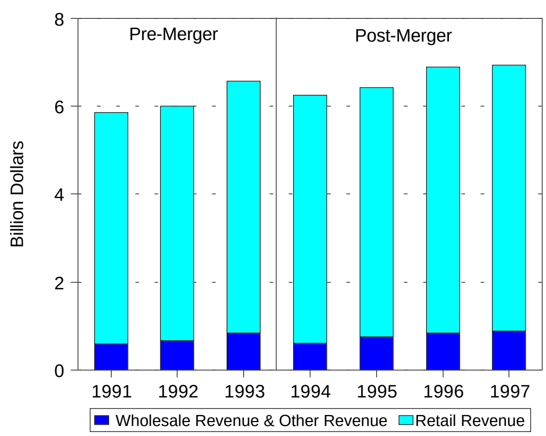
[98] Source: 1993 SEC 10-K for Entergy Corporation, " Retail Rate Matters."

[99] Fuel adjustment clauses usually provide for a bi-monthly, quarterly, semi-annual or annual adjustment to the fuel-cost test-year estimate used in the compilation of base rates, based on the actual cost of fuel purchased during the previous period. The result of fuel adjustment clauses is to place the entire risk of volatility in fuel prices on the ratepayer. If the merger results in lower fuel costs due to more efficient fuel purchasing or coordinated generation plant dispatch, these merger benefits would be entirely passed through to the ratepayer on their electric bills at the end of the period in which the lower fuel costs are realized. In this case, GSU's fuel cost recovery works not quite as automatically. The rate schedules approved by the Public Utility Commission of Texas include a fixed fuel factor to recover fuel and purchased power costs not recovered in base rates, which can be revised every six months, but each revision may be subject to a cost review procedure.

growth slowed to 1.4 percent (Figure D1).[100] This deceleration after the merger was caused by a decline in both wholesale and retail revenues. Growth in retail electric operating revenues declined after the merger, to 1.5 percent annually, from 4.1 percent annually before the merger. In comparison, total wholesale electric operating revenues before the merger were increasing at an annual rate of 19.8 percent, but after the merger (1993-1997), Entergy's growth in wholesale operating revenues slowed to a 0.9-percent annual rate. From this data, it can be concluded that even though revenues were generally increasing, the merger did not appear to stimulate additional growth.

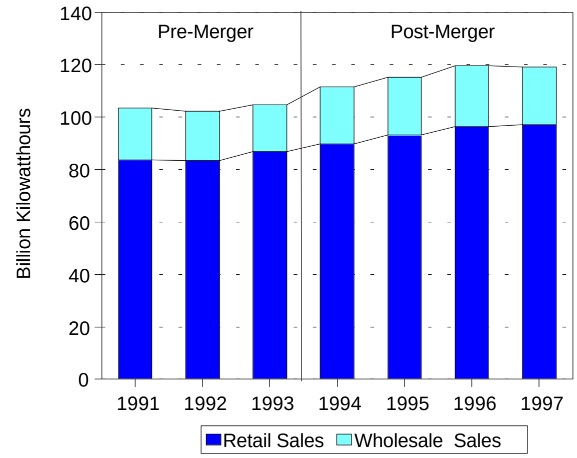
In contrast, Entergy experienced accelerated growth in electricity sales after the merger. Entergy's total sales before the merger (1991-1993) were growing at an annual rate of only 0.6 percent. After the merger (1993-1997), these grew at an annual rate of 3.3 percent (Figure D2).[101] Of this total, annual growth in retail sales increased from 1.9 percent before the merger, to 2.8 percent after the merger. Wholesale sales for Entergy/GSU, which were actually declining before the merger at an annual rate of 5.4 percent, increased to 6.1 percent annually after the merger.

Figure D1. Entergy's Electric Operating Revenue, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D2. Entergy's Retail and Wholesale Electricity Sales, 1991-1997



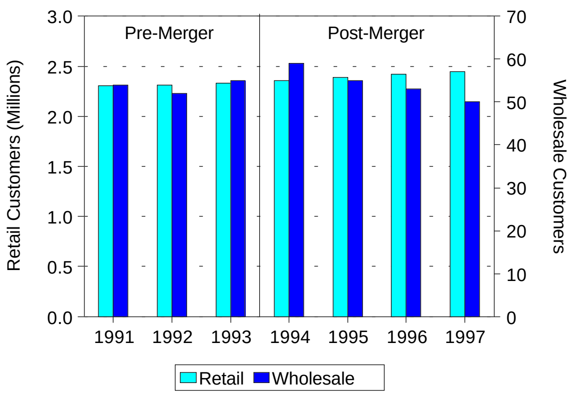
Note: Data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Along with increasing sales, the merging companies also experienced a growth in the number of retail customers after the merger (Figure D3). Before the merger, the number of retail customers was growing at an annual rate of 0.5 percent, but increased to 1.2 percent annually after the merger. Although wholesale sales were increasing, the total number of electric wholesale customers for Entergy/GSU declined after the merger mainly because GSU experienced a net loss of 9 wholesale customers over the 1994-1997 period (Figure D3). GSU may have experienced a loss of wholesale

[100] The source of all data, unless otherwise stated, is FERC Form 1 data, primarily as reported within the EIA Financial Statistics of Major U.S. Investor-Owned Electric Utilities, or the EIA Electric Power Annual, corresponding to the years mentioned. The combined totals of the four major utility retail operating subsidiaries of Entergy before the merger, and five after the merger, represent the arithmetic sum of all accounts as reported by the individual retail operating electric utilities. Consequently, duplications exist to a limited extent in the composite totals. For example, the totals for operating revenues and megawatthour sales include intercorporate sales. The wholesale sales and associated electric revenues of System Energy Resources, Inc. are eliminated from the arithmetic totals because these wholesale sales are sales to the other retail operating utilities of Entergy Corporation.

[101] Total kilowatthour sales of electricity includes retail sales, which are reported on FERC Form 1 as "sales to ultimate consumers," and wholesale sales, which are reported as "sales for resale."

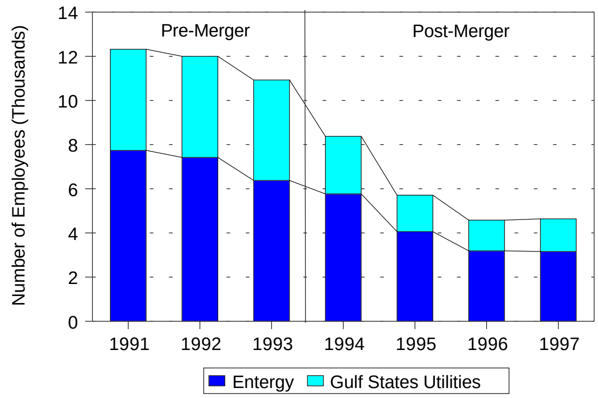
Figure D3. Entergy's Retail and Wholesale Customers, 1991-1997



Note: Entergy Data represent the sum of Entergy's electric utility subsidiaries plus Gulf State Utilities.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D4. Entergy's and Gulf States Utilities' Electric Employees, 1991-1997



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

customers because of increased competition in the wholesale electricity markets starting around 1994. In any event, the loss of wholesale customers was offset apparently by the increasing volume of wholesale sales to the remaining customers.

Entergy continued its progress in decreasing the workforce which had begun when they reorganized along functional lines in 1990,[102] and was extended to GSU after the merger in 1994. Entergy's total electric utility workforce had declined by 17.4 percent in the two years before the merger, and then was cut in half in the four years after the merger (Figure D4). GSU's workforce held steady at about 4,500 positions before the merger, and was reduced by two thirds, to 1,459 positions in the four years after the merger. In the four years following the merger, Entergy experienced a 57.6 percent reduction in its electric department workforce, from 10,915 employees to 4,633.

This statistic probably overstates the reduction in the company's total manpower because in the extension of the reorganization along functional lines effective after the merger, some of the employees and/or electric department administrative functions of GSU were probably transferred to Entergy Services. As stated previously, Entergy Services, a wholly-owned subsidiary of Entergy Corporation, provides administrative and professional support to other subsidiaries, mostly at cost. Entergy Services' workforce increased from 1,986 at the end of 1993, to 3,131 at the end of January 1998.[103]

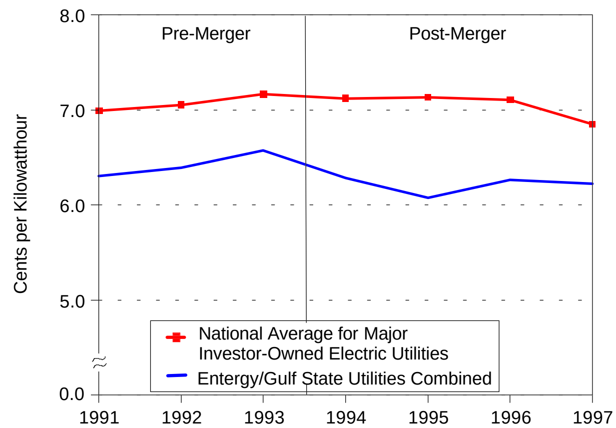
Overall Efficiency Measurements

The most important efficiency measurement to a ratepayer is the change in retail customer electricity rates. Retail electricity rate is defined as the average revenue per kilowatthour of sales to retail customers. Retail customer rates for Entergy/GSU combined increased 2.1 percent annually before the merger, but declined 1.35 percent annually after the merger (Figure D5). This decline in retail growth rates after the merger was greater than the trend experienced by all IOUs in the Nation. Between 1991 and 1993, average retail rates for all IOUs were increasing by 1.2 percent annually, and declined by an average annual rate of 1.1 percent over the 1993-1997 period. Entergy/GSU's retail rates were about 8.3 percent less than the IOU national average in 1993, but 9.1 percent less than the IOU national average by 1997.

[102] Entergy Corporation reorganized its entire operation beginning in 1990, and continuing through 1992 along functional lines, called strategic business units. The four functional units resulting from this reorganization were: Operations; Generation and Transmission; Distribution and Customer Service; and Business Support. This reorganization led to workforce reductions through elimination of redundant positions and consolidation of others. The reorganization is described by Donald Hunter in his prepared testimony before the Federal Energy Regulatory Commission in August 1992.

[103] Source: SEC 10-K reports for Entergy Corporation for corresponding years.

Figure D5. Entergy's and Major Investor-Owned Electric Utilities' Retail Electricity Rates, 1991-1997
(Nominal Dollars)

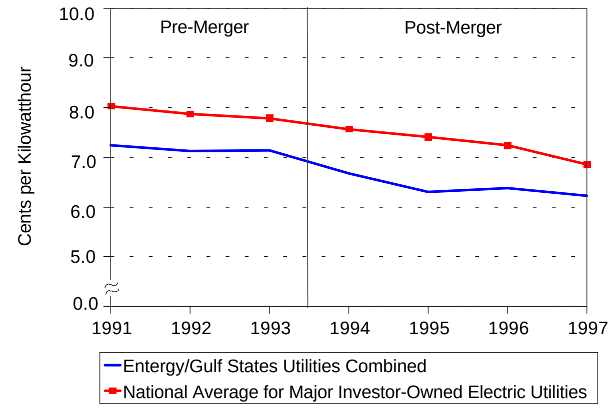


Note: Entergy data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others," and Energy Information Administration, *Electric Sales and Revenue 1997,* available on the Internet at www.eia.doe.gov.

When adjusted for inflation, the effectiveness of the merger in reducing retail electricity rates appears even more dramatic (Figure D6). Average real retail rates for Entergy/GSU combined fell 12.9 percent over the 1993-1997 period, as compared to a drop of 12.1 percent for the national average of all IOUs. In terms of annual rates, Entergy/GSU combined rates were dropping by 0.7 percent per year before the merger, and 3.38 percent per year after the merger, as compared to a drop of 3.16 percent per year over the 1993-1997 period for all IOUs. Much of the reduction in rates is attributable to GSU's annual rates, which fell 4.39 percent per year after the merger, as compared to a decline of 1.25 percent per year before the merger.

Changes in operating and maintenance (O&M) costs is a more direct measurement of operational efficiency than electricity rates. O&M costs include: fuel costs as well as nonfuel operating and maintenance charges associated with power production; transmission and distribution O&M expenses, customer-related expenses, sales expenses, and administrative and general expenses.

Figure D6. Entergy's and Major Investor-Owned Electric Utilities' Ultimate Customer Revenue, 1991-1997
(1997 Real Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

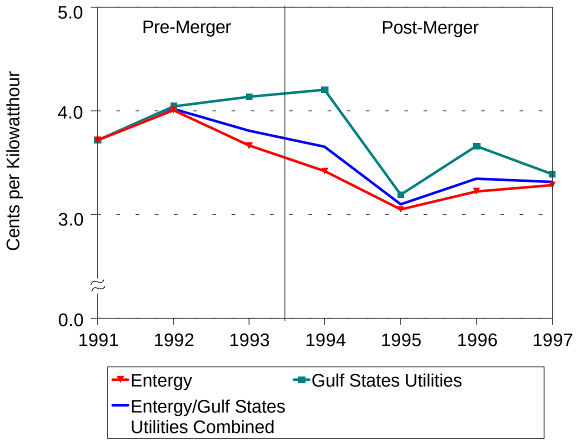
Prior to the merger, Entergy's real total O&M costs were fluctuating around 3.7 cents per kWh (Figure D7).[104] GSU's real O&M costs were increasing, from 3.71 cents per kWh in 1991 to 4.13 cents per kWh in 1993, a gain of 11.3 percent. For Entergy/GSU combined, real O&M costs increased slightly by 2.5 percent over the 1991-1993 period.

Entergy's and GSU's real O&M costs declined rapidly the first two years after the merger, but began increasing again in 1996 with a recovery in fossil fuel prices. Even with the recovery of fuel prices, however, Entergy and GSU had real O&M cost savings over the 1993-1997 period, indicating efficiency gains. GSU's O&M costs declined from 4.13 cents per kWh in 1993 to 3.39 cents per kWh in 1997, a decrease of 18 percent. Entergy's O&M costs declined from 3.66 cents per kWh to 3.28 cents per kWh, a decrease of 10.4 percent. For Entergy/GSU combined, real total O&M costs declined from an average of 3.81 cents per kWh in 1993 to 3.31 cents per kWh in 1997, a decrease of 13 percent.

Because Entergy associated some of the nonfuel O&M savings to workforce reductions, it is worthwhile to

[104] For this comparison, the O&M costs of System Energy Resources, Inc. are included because these O&M expenses are directly attributable to the sales of the other four operating electric utilities of Entergy before the merger, and also GSU after the merger, because these operating utilities purchase all of the electricity produced by the nuclear plant owned and operated by System Energy Resources, Inc.

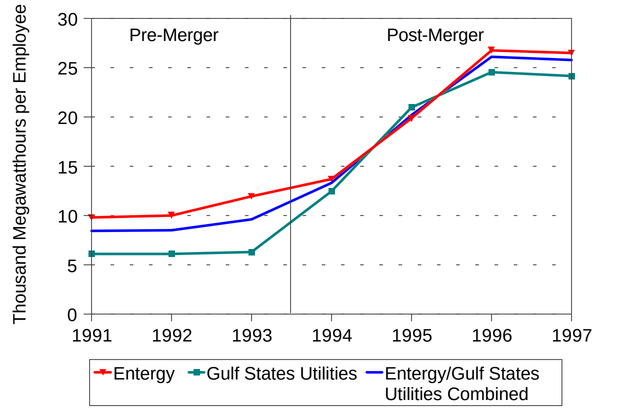
Figure D7. Entergy's and Gulf States Utilities' Total O&M Cost Minus Purchased Power Expenses, 1991-1997
(1997 Real Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D8. Entergy's and Gulf States Utilities' Megawatthour Sales, 1991-1997



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

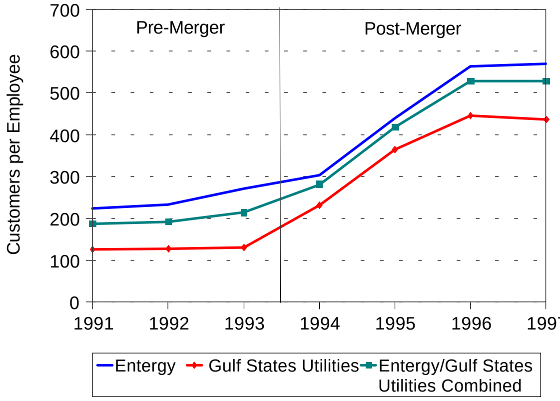
inspect indicators of electric department employee efficiency before and after the merger. Some caution must be taken when drawing conclusions using electric department employee statistics after the merger, because it is likely that some of the functions that were performed by electric department employees of GSU prior to the merger, were being performed by employees within the Entergy subsidiary, Entergy Services, after the merger. Employees within Entergy Services are not counted as electric department employees by Entergy, even when they may be fully occupied in providing administrative support services to the six major utilities of Entergy. Thus, increases in employee efficiency may be overstated when using employee department statistics as a basis for measurement. Since there are no public data that allocates Entergy Services' employees to the electric departments of the six major utilities of Entergy, no known adjustment can be made to correct the potential overstatement in manpower efficiency gains.

Entergy's and GSU's total megawatthours of sales (ultimate consumer sales and sales for resale) per electric utility department employee increased dramatically after the merger (Figure D8). In 1993, average megawatthours of sale per electric department employee equaled 11,925. By 1997, this average had increased by 122 percent to 26,469 megawatthours of sales, primarily due to sales growth and workforce reductions. For GSU, the apparent efficiency gains are even more outstanding. Total megawatthours of sales per employee increased from 6,274 in 1993 to 24,118 in 1997, a gain of 284 percent. For Entergy and GSU combined, total megawatthour sales per employee increased from 9,582 in 1993 to 25,729 in 1997, a gain of 168 percent. Entergy's dramatic gain in worker efficiency was due to: (1) an increase in the volume of retail sales and sales for resale after the merger; (2) a workforce reduction program put in place by Entergy after the merger;[105] and, as noted above, (3) a probable shift in some of the employees and functions of GSU electric utility department employees to Entergy Services after the merger.

Another measurement of employee efficiency is the average number of electricity customers served per electric department employee. Prior to the merger, in 1993, GSU was less than half as efficient by this measure than Entergy, serving 131 customers per employee as compared to 272 for Entergy (Figure D9). By 1997, the total number of customers serviced per electric department employee of GSU had grown to 436, but Entergy similarly had grown to 570. Entergy/GSU combined grew from 214 customers per electric department employee in 1993, to 528 in 1997, a 146-percent increase in

[105] Source: 1995 Entergy Corporation SEC 10-K, note 11 to financial statements, "Restructuring Costs," recorded $24.3 million in 1994, of which $23.8 million was recorded by GSU, for remaining severance and augmented retirement benefits related to the merger.

Figure D9. Entergy's and Gulf States Utilities' Electricity Customers, 1991-1997



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

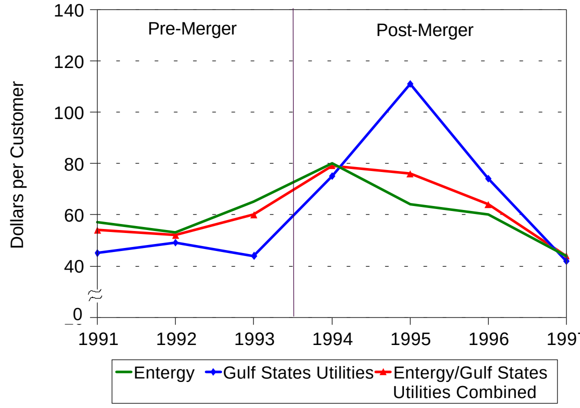
worker efficiency over four years. This was due primarily to: (1) Entergy's workforce reduction and restructuring programs[106] put in place after the merger which redefined and consolidated worker activities and sharply reduced the number of electric department employees; and (2) the probable shift in some of the administrative functions and positions of GSU to Entergy Services after the merger.

A customer-related measure of efficiency is the total customer expense per customer, adjusted for inflation. For this purpose, customer expense is defined as the sum of customer accounts and service expense and informational expense, as reported on FERC Form 1. Real customer expense per customer increased slightly before the merger, from $54.1 per customer in 1991 to $59.8 per customer in 1993 (Figure D10). By the end of 1997, this measure had declined to $43.5 per customer, a savings of 27.3 percent from 1994 levels.

Overall Profitability Measurements

After the merger, Entergy's operating income never regained the levels reached in 1993 when the two companies operated individually (Figure D11). Operating income per kilowatthour of sales fell from 1.31

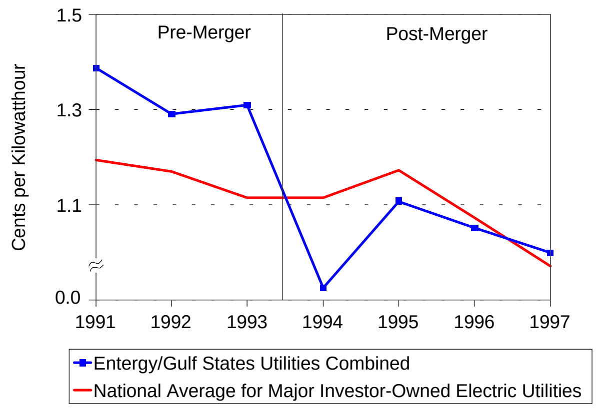
Figure D10. Entergy's and Gulf States Utilities' Customer Expense, 1991-1997
(1997 Real Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure D11. Entergy's and Major Investor-Owned Electric Utilities' Net Electric Utility Operating Income, 1991-1997
(Nominal Dollars)



Note: Data represent the sum of Entergy's electric utility subsidiaries plus Gulf States Utilities.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

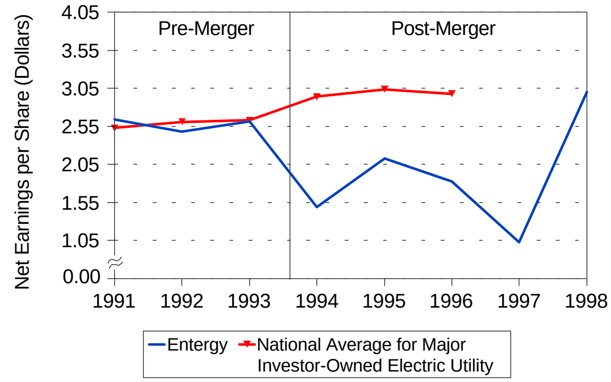
[106] During the third quarter of 1994, Entergy announced a restructuring program designed to reduce costs, improve operating efficiencies, and to increase shareholder value. The program included reductions in the number of employees and the consolidation of offices and facilities. Charges of $35.4 million were recorded in 1994 by the five operating subsidiaries of Entergy primarily for severance costs related to the expected termination of approximately 1,850 employees. This was reported in Entergy's 1994 SEC 10-K report.

cents per kWh in 1993 to 1.0 cents per kWh in 1997, a decline of 23.7 percent. Important factors causing this decline were mandated base rate reductions after the merger and rate cap agreements entered into in connection with the merger, all of which constrained base rate operating revenues. Another factor was potential losses associated with the River Bend nuclear plant, including the establishment of reserves for the financial effects of potential adverse rulings by regulatory agencies. (Entergy also wrote off deferred costs associated with the River Bend plant of $169 million, net of taxes, effective January 1, 1996). While before the merger, Entergy and GSU combined were more profitable on a net kilowatthour of sales basis than all IOUs, for the first two years after the merger, they were significantly less profitable than all IOUs on the average, but by the 1996-1997 period, as merger savings and operating efficiencies began to become significant, Entergy began to be about as profitable as all IOUs on average.

Actual net earnings per average common share for Entergy (including all regulated and non-regulated subsidiaries), were lower in each year after the merger through 1997 compared with 1993 levels (Figure D12). The vast number of acquisitions and joint ventures made both domestically and in foreign countries after the merger through 1997 failed to produce profits to offset the decline in operating income of Entergy's major domestic operating utilities. Entergy's earnings per common share dropped from a 1993 pre-merger level of $2.62 to a post-merger level in 1997 of $1.03.

The decrease in earnings per share was a result in part of Entergy's aggressive expansion in both foreign and domestic markets, particularly in non-regulated businesses. Between 1993 and 1997, Entergy's investments in businesses other than domestic regulated utility business had grown from $142 million to over $1.3 billion.[107] But not all of these investments turned out to be sound ones, in terms of producing positive net income. In the years 1996 and 1997, all of the business segments of Entergy, other than domestic utility operations, when combined, resulted in net losses. These investments had left Entergy overextended financially, and debt had reached unacceptable levels, at 56.7 percent of total capital by the end of 1997. In 1998, Entergy was forced to reduce its dividend from $1.80 to $1.50 per common share.

Figure D12. Entergy's Net Earnings per Average Common Share, 1991-1998



Note: National Average for Major Investor-Owned Electric Utility unavailable for 1997 and 1998.

Source: Entergy and Gulf States Utilities, *Annual Report*, 1991-1998.

By mid-1998, Entergy changed its strategy, changed its chief executive officer (CEO), and began to refocus on its core operations. It also began a huge divestment program, selling off many of the assets acquired since 1993. The new CEO decided to refocus on three core competencies: domestic utility operations, global power development, and nuclear power operations. The catchy name for this new strategy was Divest to Reinvest.[108]

Regarding domestic utility operations, the new CEO indicated that service performance had suffered due to the concentration on reducing utility costs over recent years. For example, in 1997 customers received over 400,000 busy signals when attempting to call Entergy for assistance. At the urging of the regulators, Entergy committed to new service standards and practices that are expected to improve service reliability and customer responsiveness. Entergy decided to change all this in order to be the supplier of choice when their customers are given a choice. In addition, Entergy decided to invest $0.5 billion in its power marketing and trading business because the need for a superior energy- and price-risk management function will increase as the industry restructures and trading in wholesale markets plays a larger role in determining the price that utilities, and ultimately consumers, pay for electricity.

In 1998, Entergy also set a goal of becoming one of the top 10 wholesale generators and traders in Europe, the

[107] Sources: Entergy Corporation's SEC 10-K reports for 1993 and 1997.
[108] Source for this paragraph and the next three: Entergy Corporation's Annual Report for 1998.

Americas, and Australia, primarily by developing new merchant power generation plants using gas turbine advanced technology. To realize this goal, Entergy allocated $4.0 billion in investment, and expects the global development business to contribute significantly to earnings beginning in 2000.

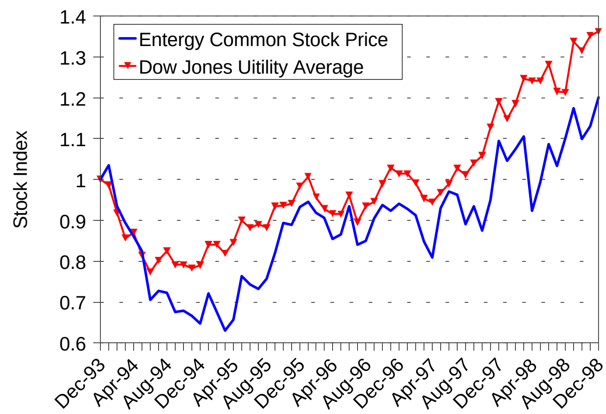
Entergy believes that it is one of only a few companies that has the skilled personnel and the scale of operations necessary to successfully operate nuclear power plants in a competitive market. Entergy sees significant expansion opportunities through the purchase and management of additional nuclear plants and through decommissioning plants. As a result, in 1998 Entergy allocated $0.5 billion in investment for expansion of its nuclear power operations.

By the end of 1998, the result of the change in strategy was an increase in earnings per share to $3.00, up from $1.03 in 1997 (Figure D12). The increase did not come from increases in total operating income, which declined from 1997 to 1998, but, at least in part, from the gain on the sale of non-regulated businesses.

Apparently, investors were not as optimistic about the prospects for increased profits from the Entergy/GSU merger or the aggressive acquisition strategy that was being pursued by Entergy over the 1994-1997 period. When indexed to the Dow Jones Utility Average, Entergy's price of common stock fell below the index within six months after the close of the merger, and stayed there through the end of 1998 (Figure D13). Total return on common stock (dividend yield plus percentage price appreciation of the stock) suffered in 1994 as the stock price fell precipitously (Figure D14). The price drop occurred as Entergy reported lower earnings and the Federal Reserve implemented a series of interest rate increases aimed at warding off inflation. The stock price recovered most of the price decline in 1995, a very good year for utility and other stocks in general, but failed to close the gap with the average for all utility stocks over subsequent years. As a result, total returns on common stock were disappointing in the 1994-1998 period, reaching only 8.8 percent in 1998, the year that Entergy's dividend was cut. The arithmetic average of total returns over the 1994 to 1998 period was only 6.6 percent.

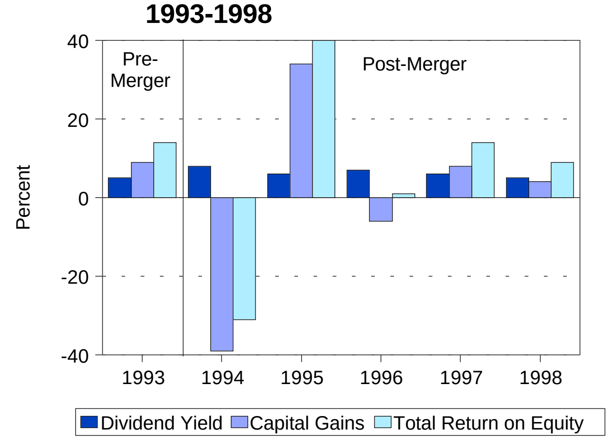
On the positive side, the price of Entergy's common stock increased almost 10 percent from December 31, 1997 to December 31, 1998, indicating that investors apparently reacted positively to the change in Entergy's management and the new Entergy strategy for growth and profitability.

Figure D13. Comparison of Entergy Common Stock Price and Dow Jones Utility Average, December 1993 Through December 1998



Source: New York Stock Exchange and Dow Jones Reports.

Figure D14. Entergy's Total Return on Equity, 1993-1998



Source: Entergy's Annual Reports, 1993-1998.

Assessment of Merger Effects on Ratepayers and Shareholders

Based on the overall growth, efficiency, and profitability measurements discussed in this section, the following preliminary conclusions can be drawn:

- Entergy's merger with GSU in 1993 failed to stimulate growth in total electric operating revenues of the combined company primarily because of customer base rate reductions in subsequent years. Before the merger (1991-1993), growth in total electric operating revenues for the two companies was increasing by 5.8 percent annually;

after the merger (1993-1997), annual growth in revenue had slowed to 2.8 percent. The decline in annual growth of operating revenues was experienced in both the retail and wholesale markets.

- Entergy's total kilowatthour sales (including both retail and wholesale sales) were probably stimulated by the merger, primarily due to both customer rate reductions and an increase in the growth of retail customers. Total sales for Entergy and GSU before the merger (1991-1993) were growing at an annual rate of only 0.6 percent, but after the merger (1993-1997), annual growth of 3.3 percent was experienced. Annual growth in the total number of retail customers increased after the merger, to 1.2 percent from 0.5 percent before the merger, but the total number of wholesale customers declined after the merger.

- Retail customer rates were reduced significantly after the merger, when measured in both nominal and inflation-adjusted dollars. In fact, the most certain result of the merger was retail customer rate reductions, particularly at GSU. This could be expected because 95 percent of the merger savings was expected to be attributed to GSU operations. Average rates for the two companies were increasing 2.1 percent annually before the merger, but declined 1.35 percent annually after the merger (in nominal dollars). Retail customers of the four original operating utilities of Entergy experienced a drop in retail rates of 3.2 percent, and 10.9 percent when adjusted for inflation. GSU's customer rates dropped 9.1 percent over the 1993-1997 period, and 16.4 percent when adjusted for inflation.

- Entergy's operational efficiency was somewhat improved after the merger. Real total O&M costs per kilowatthour of net generation declined 13 percent in the post-merger period, while this efficiency measurement increased slightly, by 2.5 percent, in the 1991-1993 period before the merger. Entergy's electric department workforce efficiency improved as measured by both megawatthour sales per employee and customers served per employee, and its real customer expense per customer declined. (Conclusions regarding electric department workforce efficiency gains have to be qualified by the uncertainty in the data derived from the probable transfer of some employee work requirements associated with GSU electric department administrative functions to Entergy Services after the merger.)

- Shareholders of Entergy did not experience increased profits or higher total returns on common stock equity as a result of the merger. This was probably a result of concessions made by Entergy when obtaining merger approval from the various regulatory agencies, that allocated most of the merger savings to ratepayers. In addition, in hindsight, Entergy may have paid too high a price for GSU. The $2.3 billion price tag was some $380 million in excess of the historical cost of the GSU net assets acquired,[109] and GSU had severe financial problems linked to the recovery of costs associated with the River Bend nuclear plant that, to date, were not resolved in GSU's favor. As a result, growth in price of Entergy's common stock lagged growth in the Dow Jones Utility average over the 1994-1998 period, shareholders received a cut in dividends per share in 1998, and average annual total returns on common stock equity were only 6.6 percent over the 1994-1998 post-merger period, about equal to the yield of a long term Treasury Bond that has no risk.

- Entergy itself, as a company, did not appear to benefit strategically from the merger. The stringent cost reduction measures put in place in the 1993-1997 period resulted positively in customer rate reductions, but system reliability and customer service suffered. As a result, corrective measures had to be taken by the new CEO in mid-1998, and, by that time, Entergy realized it had to refocus on core operations, including domestic utility operations, if it were to be prepared for customer choice.

Analysis of Estimated Pre-Merger and Post-Merger Savings and Costs

As described previously, in August of 1992, when Entergy first applied to the FERC for approval of the merger, Entergy estimated merger savings would be approximately $539 million over the first five years following the merger, and approximately $1.7 billion over the first 10 years. These savings were to be derived

[109] Source: Entergy Corporation's SEC 10-K for 1995, Note 1 to Consolidated Financial Statements for Entergy.

primarily from the fuel cost savings over the decade, nonfuel O&M savings over the decade, and deferred resource capacity expenditures over the 1999-2003 period. (See Table D1 for a summary of estimated pre-merger and post-merger cost savings.) Each of these merger savings categories is analyzed below, followed by an itemization of recorded merger costs.

Fuel Cost Savings

Projected fuel cost savings would be primarily from: (1) greater efficiencies in the purchasing of fossil fuels for steam generation plants due to the consolidation of purchasing operations; and (2) greater use of primarily coal-fired generation plants and less use of oil- and gas-fired generation plants, as a result of coordinated generation dispatch.[110] Therefore, a reasonable way to observe whether these savings were achieved, using public data, is to examine changes in steam-power fuel expense per kilowatthour of electricity generation after the merger.

Changes in fuel expenses will occur because of market price changes, Entergy's ability to obtain better prices relative to the market, attainment of higher average efficiencies for each type of fossil-fueled generation unit,

Table D1. Entergy/Gulf States Utilities Pre-Merger Estimated Cost Savings Compared to Post-Merger Estimated Cost Savings

Savings Category	Pre-Merger Estimated Savings ($ Millions)	Post-Merger Estimated Savings	
		Estimates ($ Millions)	Comments
Savings for 5 Years After Merger Fuel Cost Savings	$274	$200 (4 years)	An estimated $200 million was saved from 1994 through 1997. At this rate, Entergy will likely achieve its 5-year, pre-merger estimated savings.
Non-Fuel Operation and Maintenance Cost Savings GSU . . . . Entergy . . . . Subtotal	 $234 31 $265	 $280 647 $921 (generation weighted average)	Entergy reorganized its company in early 1994, and the effects of the merger cannot be isolated from the effects of the reorganization. It is likely, however, that the pre-merger estimates were realized.
Total (5 year savings)	$539	$1121	
Savings for 10 Years After Merger Fuel Cost Savings	$849	Not estimated.	Based on early savings estimates, Entergy is likely to achieve most of the pre-merger estimates
Non-Fuel Operation and Maintenance Cost Savings GSU . . . . Entergy . . . . Subtotal	 $578 95 $673	Not estimated.	Based on early savings estimates, Entergy will likely achieve these pre-merger estimated cost savings.
Deferral of Resource Capacity Expenses	$184	Not estimated.	No data were available to make an estimate or judgement as to whether these savings will be achieved.
Total (10 year savings)	$1,706	Not estimated.	

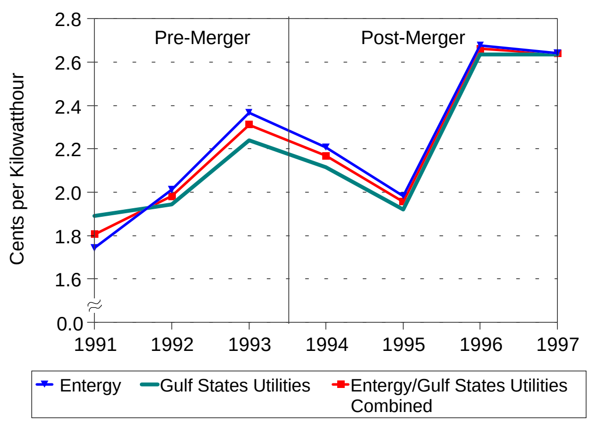
Source: **Pre-Merger**: Federal Energy Regulatory Commission, Entergy/GSU Merger Application, 1993. **Post-Merger**: Federal Energy Regulatory Commission, Form 1, 1993-1997.

Note: Merger implementation costs are estimated to be $194 million. These costs should be subtracted from the savings to derive net merger savings.

[110] Op. cit., Prepared Direct Testimony of Frank F. Gallaher, August 1992.

and changes in the mix of generation plants dispatched. Entergy should be given credit for positive savings from the latter three factors, but should not be credited or penalized for market price changes, which, in a competitive market, are beyond Entergy's control. Entergy's fuel expenses, unadjusted for changes in market prices, decreased in the two years following the merger, but increased to higher levels in 1996 through 1997 (Figure D15). In order to factor out changes in the market price of fuel from the improvements in operation the company made that may lower fuel expenses, a composite market price index was developed.[111] The composite market price index indicates how the average costs of fossil fuels would have changed at Entergy, GSU, and Entergy/GSU combined, if these entities continued to purchase the same relative quantities of each type of fossil fuel as they did in 1993, and with the same purchasing efficiency as experienced in 1993. The difference between the composite market price index and actual fuel expenses represent the savings in fuel

Figure D15. Entergy's Steam Fuel Expense, 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

expenses attributable to improved fuel management after the merger. (Table D2 contains the value of the composite market price index and an analysis of fuel cost savings.)

Entergy and GSU together accumulated approximately $199.5 million in fossil fuel savings over the 1994-1997 period. This compares well to the $201.5 million estimated by Entergy for the corresponding period.[112] Fuel savings are not linear; 4-year savings were estimated at $201.5 million while 5-year savings were estimated at $274 million. Since these savings are derived from changes in purchasing practices and the introduction of coordinated dispatch of generation plants, more savings are likely, and Entergy is likely to achieve its estimated $274 million in fossil fuel savings over the first years after the merger, and $849 million over the first 10 years. Also, Entergy's assertion that GSU would accrue nearly all of the fossil fuel savings was accurate. GSU was allocated all of the fossil fuel savings over the first four years after the merger (Table D2). Entergy projected that GSU would accrue about 83 percent of the cumulative fossil fuel savings after four years, 87 percent after 5 years, and 93 percent after 10 years.[113]

Savings from Nonfuel Operation and Maintenance Expenses

The merging companies projected that merger savings from nonfuel O&M expenses would amount to $265 million accumulated over the first 5 years after the merger, and $673 million over the first 10. (These nonfuel savings estimates are net of Entergy's estimated $12.4 million of merger costs associated with early retirement costs.) Of these savings, GSU was projected to accrue $234 million over 5 years, and $578 million over 10 years. One way to use public data to determine whether these savings were achieved is to examine nonfuel O&M expenses (minus purchased power expense) per kilowatthour of electricity generation before and after the merger.[114]

[111] This composite market price index was developed in three steps: (1) A weighted average cost per million Btu of fossil-fuel receipts by fuel type (natural gas, petroleum, and coal) at electric utilities within the East South Central and West South Central Census Divisions was calculated for each year from 1993 through 1997, using data published by EIA in its *Electric Power Annual*; (2) The proportion of fossil fuel receipts during 1993, the year before the close of the merger, at Entergy's four original operating utilities, GSU, and all five operating utilities was determined, using data from EIA's *Cost and Quality of Fuels at Electric Utility Plants 1993*; and (3) The 1993 proportions of receipts by fuel type for Entergy, GSU, and Entergy/GSU were applied to the average regional prices developed for each year during step 1.

[112] Op. cit., Prepared Direct Testimony of Frank G. Gallaher, August 1992, Exhibit FFG-7.

[113] *Ibid.*

[114] In this nonfuel O&M cost category, Entergy attempts to distinguish between cost savings that could have occurred on a stand-alone basis, and cost savings that could occur only because of the merger. They only count the latter as merger savings. Using the FERC Form 1 data, it is impossible to make this distinction in measured cost savings. Therefore, when all measured savings are attributed to the merger, such savings may be overstated.

Table D2. Estimated Fossil Fuel Cost Savings Due to the 1993 Entergy/Gulf States Utilities Merger

Cost Item	1993	1994	1995	1996	1997	Total
Entergy Subsidiaries						
Steam Fuel Expense (Thousand Dollars)	669,227	674,402	683,884	847,185	828,979	3,703,677
Steam Generation (Megawatthours)	28,267,839	30,552,746	34,496,406	31,642,361	31,390,122	156,349,474
Steam Fuel Expense per Steam Kilowatthour (Cents/kilowatthour)	2.367	2.207	1.982	2.677	2.641	2.369
Difference from 1993 (Cents/kilowatthour) . . .	--	-0.160	-0.385	0.310	0.273	0.001
Percent Difference from 1993 (Percent)	--	-6.763	-16.261	13.091	11.550	0.059
Fuel Savings with Market Price Changes (Thousand Dollars)	--	48,919	132,801	(98,068)	(85,834)	(2,181)
Composite Market Price Index (Cents/million Btu)	198.35	185.77	186.65	210.12	211.67	--
Difference from 1993 (Cents/million Btu)	--	-12.58	-11.7	11.77	13.32	--
Percent Difference from 1993 (Percent)	--	-6.342	-5.899	5.934	6.715	--
Savings Percent Net of Market Price Changes (Percent)	--	0.42	10.36	-7.16	-4.83	--
Fuel Savings Net of Market Price Changes (Thousand Dollars)	--	3,044	84,628	(53,616)	(35,928)	(1,873)
Gulf States Utilities						
Steam Fuel Expense (Thousand Dollars)	495,260	480,782	472,632	524,784	527,776	2,501,234
Steam Generation (Megawatthours)	22,128,494	22,730,780	24,614,472	19,921,377	20,019,805	109,414,928
Steam Fuel Expense per Steam Kilowatthour (Cents/kilowatthour)	2.238	2.115	1.920	2.634	2.636	2.286
Difference from 1993 (Cents/kilowatthour) . . .	--	-0.252	-0.447	0.267	0.269	-0.081
Percent Difference from 1993 (Percent)	--	-10.659	-18.894	11.271	11.355	-3.440
Fuel Savings with Market Price Changes (Thousand Dollars)	--	57,358	110,103	(53,155)	(53,817)	60,489
Composite Market Price Index (Cents/million Btu)	228.44	203.00	179.70	233.83	241.71	--
Difference from 1993 (Cents/million Btu)	--	4.65	-18.65	35.48	43.36	--
Percent Difference from 1993 (Percent)	--	2.344	-9.403	17.888	21.860	--
Savings Percent Net of Market Price Changes (Percent)	--	13.00	9.49	6.62	10.51	--
Fuel Savings Net of Market Price Changes (Thousand Dollars)	--	69,974	55,311	31,208	49,792	206,285
Entergy and GSU Combined						
Steam Fuel Expense (Thousand Dollars)	1,164,487	1,155,184	1,156,516	1,371,969	1,356,755	6,204,911
Steam Generation (Megawatthours)	50,396,333	53,283,526	59,110,878	51,563,738	51,409,927	265,764,402
Steam Fuel Expense per Steam Kilowatthour (Cents/kilowatthour)	2.311	2.168	1.957	2.661	2.639	2.335
Difference from 1993 (Cents/kilowatthour) . . .	--	-0.199	-0.411	0.293	0.272	-0.033
Percent Difference from 1993 (Percent)	--	-8.425	-17.358	12.388	11.474	-1.382
Fuel Savings with Market Price Changes (Thousand Dollars)	--	106,277	242,905	(151,223)	(139,651)	58,308
Composite Market Price Index (Cents/million Btu)	209.87	192.36	183.99	219.19	223.17	–

Notes at end of table.

Table D2. Estimated Fossil Fuel Cost Savings Due to the 1993 Entergy/Gulf States Utilities Merger (Continued)

Cost Item	1993	1994	1995	1996	1997	Total
Difference from 1993 (Cents/million Btu)	--	-5.99	-14.36	20.84	24.82	--
Percent Difference from 1993 (Percent)	--	-3.020	-7.240	10.507	12.513	–
Savings Percent Net of Market Price Changes (Percent)	--	5.41	10.12	-1.88	1.04	–
Fuel Savings Net of Market Price Changes (Thousand Dollars)	--	68,182	141,590	(22,963)	12,649	199,457

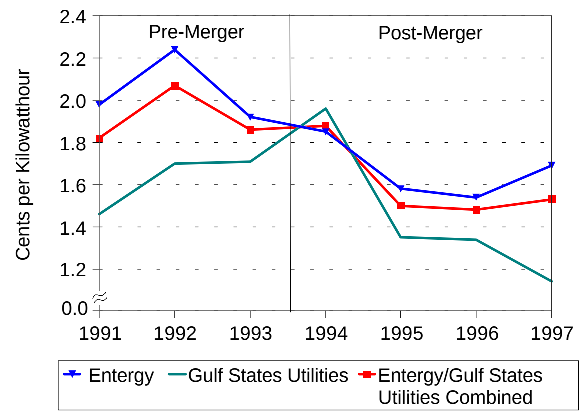
-- = Not applicable.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Entergy experienced substantial reductions in nonfuel O&M expenses (Figure D16).[115] Associated savings are computed on Table D3. Unfortunately, the savings shown on Table D3 include savings derived from the Entergy / GSU merger, as well as from the restructuring and reorganization that Entergy imposed on all its operating utilities beginning in the third quarter of 1994.[116] Isolating the individual effects on nonfuel O&M expenses using public data is not possible. However, from the fact that the estimated savings at GSU for the first four years after the merger, at $280 million, exceed the estimate for merger savings at GSU for five years, at $234 million, and because the reorganization of functions and employees at GSU was an integral component of plans associated with the merger, it is likely that the savings in this overall nonfuel O&M category were realized at GSU. The apparent savings of $647 million over 4 years in this category for Entergy's subsidiaries dwarf the estimated amount associated with the merger, of $31 million over 5 years. It is unlikely that Entergy underestimated the expected cost savings from the merger by such a large amount. Therefore, it is more likely that most of these savings were attributable to the Entergy reorganization and restructuring than the merger.

Thus, based on these findings, it can be concluded that an analysis of public data support Entergy's achievement of estimated merger savings in this category over the 1994-1997 period. Since the efficiency measures associated with the merger are expected to promote permanent changes in Entergy / GSU's organization, it is probable that Entergy will achieve its merger savings estimates associated with nonfuel O&M expenses over both the first five years and the decade after the merger.

Figure D16. Entergy's Total Nonfuel Expense Minus Purchased Power Expense, 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.

Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

This conclusion is further supported by an examination of cost changes in each of the areas targeted by Entergy / GSU for nonfuel O&M merger savings, as described in the remaining paragraphs of this section.

[115] System Energy Resources, Inc. is included within Figures 3-3 and 3-4 because all four of Entergy's nuclear power plants were contained in Entergy's nonfuel O&M analysis, including Grand Gulf in which System Energy has a 90-percent ownership and leasehold interest. System Energy sells all the capacity and energy of Grand Gulf to the other original four operating utilities of Entergy. Entergy actually prepared the nonfuel O&M analysis on a strategic business unit basis. On this basis, all of Entergy's four nuclear power plants are contained within the energy operations unit. In fact, GSU's nuclear power unit at River Bend was benchmarked to measure potential merger savings against the Grand Gulf power plant. Entergy allocated all the nonfuel merger savings to the operating utilities in its final tables within the FERC application.

[116] Op. cit., Entergy Corporation's 1994 SEC 10-K.

Table D3. Entergy/Gulf States Utilities Merger Savings Associated with Nonfuel O&M Expense

Cost Item	1993	1994	1995	1996	1997	Total
Entergy's Subsidiaries						
Nonfuel O&M Expense (Thousand Dollars)	2,306,211	2,210,019	2,066,231	2,243,722	2,327,326	11,153,509
Purchased Power Expense (Thousand Dollars)	1,185,949	1,075,897	1,101,221	1,285,409	1,274,649	5,923,125
Nonfuel O&M Expense Minus Purchased Power Expense (Thousand Dollars)	1,120,262	1,134,122	965,010	958,313	1,052,677	5,230,384
Net Generation (Megawatthours)	58,199,360	61,250,737	61,260,115	62,368,263	62,237,805	305,316,280
Nonfuel O&M Minus Purchased Power per Net Generation kWh (Cents/kilowatthour)	1.925	1.852	1.575	1.537	1.691	1.713
Nominal Unit Savings (Cents/kilowatthour)	--	0.073	0.350	0.388	0.233	--
Total Savings (Thousand Dollars)	--	44,875	214,168	242,195	145,320	646,557
Gulf States Utilities						
Nonfuel O&M Expense (Thousand Dollars)	576,920	715,612	577,062	626,439	609,765	3,105,798
Purchased Power Expense (Thousand Dollars)	134,936	203,773	169,767	295,960	327,037	1,131,473
Nonfuel O&M Expense Minus Purchased Power Expense (Thousand Dollars)	441,984	511,839	407,295	330,479	282,728	1,974,325
Net Generation (Megawatthours)	25,809,003	26,109,141	30,165,185	24,706,561	24,834,215	131,624,105
Nonfuel O&M Minus Purchased Power per Net Generation kWh (Cents/kilowatthour)	1.713	1.960	1.350	1.338	1.138	1.500
Nominal Unit Savings (Cents/kilowatthour)	--	-0.248	0.362	0.375	0.574	--
Total Savings (Thousand Dollars)	--	(64,715)	109,289	92,625	142,563	279,762
Entergy and Gulf States Utilities						
Nonfuel O&M Expense (Thousand Dollars)	2,883,131	2,925,631	2,643,293	2,870,161	2,937,091	14,259,307
Purchased Power Expense (Thousand Dollars)	1,320,885	1,279,670	1,270,988	1,581,369	1,601,686	7,054,598
Nonfuel O&M Expense Minus Purchased Power Expense (Thousand Dollars)	1,562,246	1,645,961	1,372,305	1,288,792	1,335,405	7,204,709
Net Generation (Megawatthours)	84,008,363	87,359,878	91,425,300	87,074,824	87,072,020	436,940,385
Nonfuel O&M Minus Purchased Power per Net Generation kWh (Cents/kilowatthour)	1.860	1.884	1.501	1.480	1.534	1.649
Nominal Unit Savings (Cents/kilowatthour)	--	-0.024	0.359	0.380	0.326	--
Total Savings (Thousand Dollars)	--	(21,389)	327,869	330,479	283,814	920,772

–- = Not applicable.

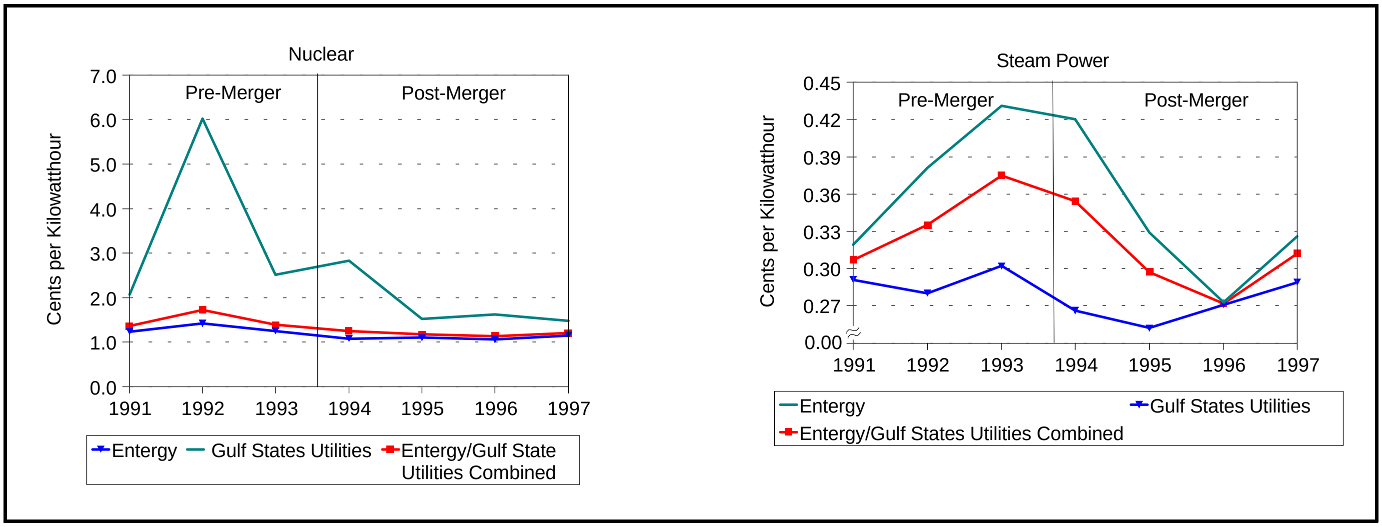
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

One of the merger goals was to bring the River Bend nuclear power plant, which was 70 percent owned by GSU, closer to the efficiencies achieved by the other Entergy nuclear plants. In 1993, GSU's nonfuel nuclear power production expenses per kilowatthour were more than double (102 percent higher) that of the other Entergy nuclear units. By 1997, GSU's nonfuel power production expenses were only 28.7 percent higher (Figure D17).

Another target for nonfuel O&M merger savings was fossil-fuel power production at GSU. GSU's nonfuel O&M steam power production expense per kilowatthour declined by 4.3 percent in the post-merger period, from 3.02 mills per kWh in 1993 to 2.89 mills per kilowatthour in 1997 (Figure D17). For the fossil fuel plants at the four original operating subsidiaries of Entergy, the reorganization of Entergy which began in the third quarter of 1994 produced even more dramatic reductions in the nonfuel O&M expense per kWh.

Retail distribution cost was another target for merger savings mentioned by Entergy during the FERC application process. Retail distribution expense per kilowatthour dropped by 17 percent after the merger for Entergy/GSU, from 2.08 mills per kWh in 1993 to 1.72 mills per kWh in 1997 (Figure D18). For GSU alone, retail distribution expense per kilowatthour dropped by 23 percent; the original operating four utilities of Entergy dropped by 14 percent.

Figure D17. Entergy's Nonfuel Power Production Expenses, 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Entergy also expected to realize savings by reducing customer and administrative expenses (Figure D18). Although the path taken was erratic over the four years in both measures, by 1997 cost savings were apparent in both. Entergy / GSU experienced a drop of 21 percent in customer expense, from $54.97 per customer in 1993, to $43.51 in 1997. Similarly, Entergy / GSU enjoyed a drop of 18 percent in administrative and general expenses, from $198.57 per customer in 1993 to $162.63 per customer in 1997.

Savings from Deferral of New Resource Capacity

The estimated $184 million associated with deferral of resource capacity additions represented the greatest potential source of merger savings for Entergy. Without the merger, on a stand-alone basis, the Entergy system was projected to incur a resource capacity deficit in 1999; GSU not until 2006. The combined Entergy and GSU system was projected to show a resource capacity deficit not until the year 2001, and a smaller resource capacity deficit than that for Entergy as a stand-alone system.[117]

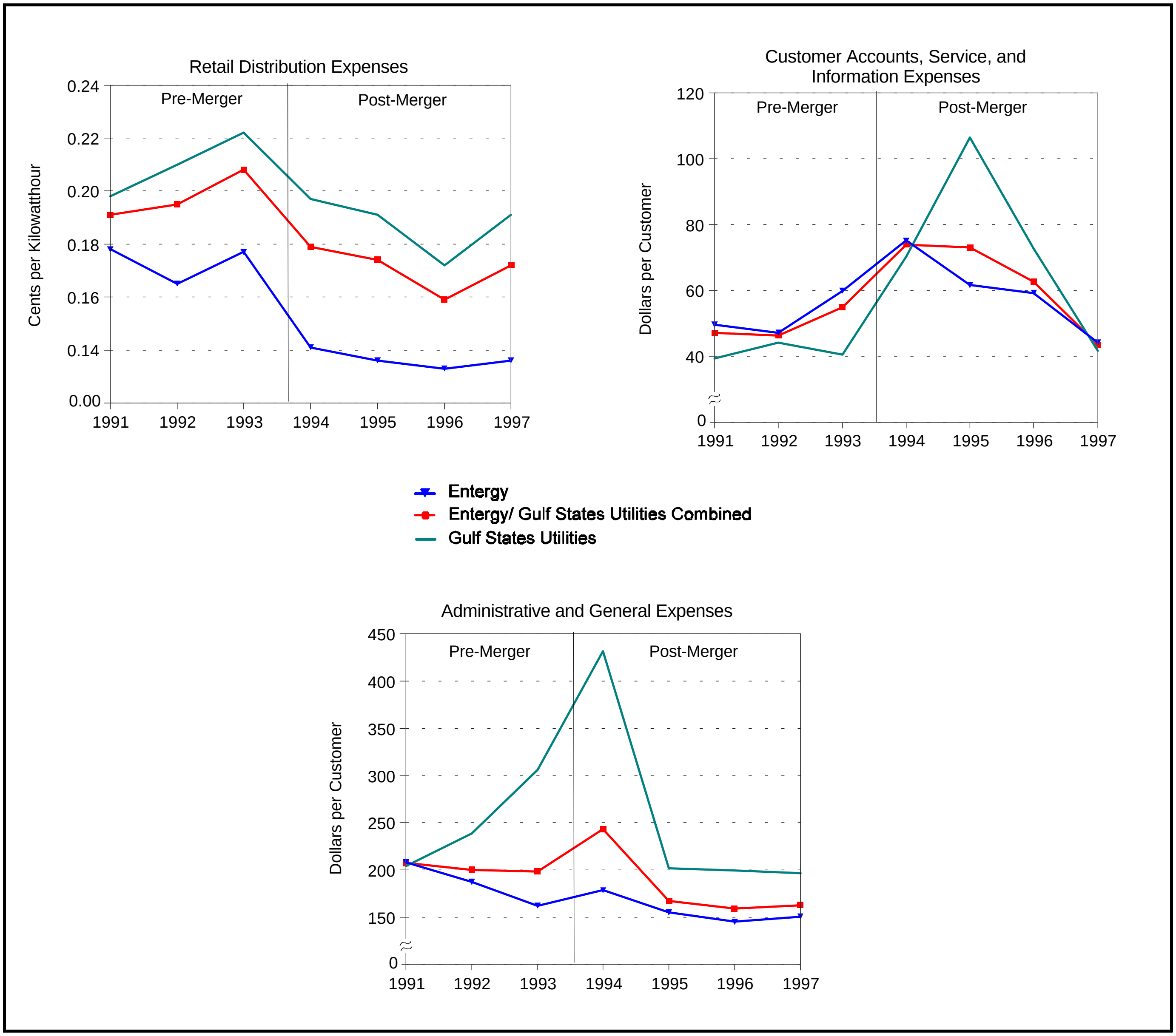
Determining whether this deferral of capacity additions will actually occur, based on public data, is made difficult by Entergy's definition of resource capacity. Entergy defines available resource capacity options to include: (1) implementation of demand-side management programs; (2) installation of new generating capacity; (3) the repowering or delayed retirement of generation plants; and / or (4) the utilization of capacity from independent power producers or qualifying facilities. At any time, the option to be implemented would be determined by least cost planning.[118] Thus, in absence of obtaining and reviewing recent Integrated Resource Plans filed with State regulatory commissions, if any, there is no sure way of determining whether new resource capacity additions are being planned as of the end of 1998. Entergy's 1998 SEC 10-K did include estimated construction expenditures for the years 1999-2001 in the range of $1.3 to $1.4 billion per year, but there was no breakdown of these numbers by type of construction. Thus, based the publicly available data reviewed herein, no conclusion can be drawn as to whether the estimated merger savings associated with the deferral of resource capacity in the 1999-2003 timeframe will be realized.

Merger Costs

By the end of 1993, total merger costs were estimated at approximately $111 million. These included: (1) $33.5 million of merger transaction costs; (2) one-time capital

[117] Op. cit., Prepared Direct Testimony of Frank F. Gallaher, August 1992.
[118] *Ibid.*, p. 43.

Figure D18. Entergy's Other Nonfuel Expenses 1991-1997
(Nominal Dollars)



Note: Entergy data represent the sum of Entergy's electric utility subsidiaries.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

costs of $37 million, incurred over the first three years after the merger to add or modify facilities and equipment at GSU's River Bend nuclear plant; (3) one-time capital costs of $28 million, incurred over the first four years after the merger to conform GSU fossil steam generation equipment to Entergy specifications; and (4) one-time O&M expenditures of $12.4 million for the implementation of an early retirement program and directors' and officers' insurance premiums in order to facilitate workforce reductions and administrative cost savings. Only the O&M costs were subtracted from Entergy's estimated merger savings to derive publicly announced net merger savings.

The capital costs associated with the merger were not reported as separate items in Entergy's SEC 10-K reports for 1994 or subsequent years. Because they were targeted to specific construction expenditures at generation plants, however, and these plants did show efficiency gains as described above, it is probable that these capital expenditures (totaling $65 million) were invested as planned.

In 1994, GSU recorded expenses totaling $49 million net of tax effects (approximately $70 million on a pre-tax basis) for early retirement and other severance-related plans and the payment to financial consultants involved in merger negotiations.[119] Additionally, Entergy recorded $24.3 million in 1994 and $1.6 million in 1996 related to remaining severance and augmented retirement benefits related to the merger. (These accruals were nearly completely expensed in 1995 and 1996.)[120] Thus, recorded costs associated with the merger aggregated to about $129.4 million ($33.5 + $70 +$24.3 + $1.6). As discussed above, additional capital costs estimated by Entergy and probably incurred as planned were $65 million, yielding total merger costs of about $194 million.

Assessment of Realized Merger Costs and Savings

From the above discussion, the following conclusions can be drawn:

1. Over the first four years after the merger, Entergy realized the merger fuel savings it had estimated from consolidating purchasing and coordinating generation dispatch. Since these savings were induced by permanent changes, it is likely that Entergy will realize the $274.5 million in merger-induced fuel savings over the first 5 years, and $849 million over the first 10.

2. Entergy is also likely to realize its merger savings in nonfuel O&M expenses, estimated at $265 million over the first 5 years, and $673 million over the first 10 years. At the end of 4 years, GSU, where most of these savings were to occur, had realized more savings ($280 million) than projected for the first 5 years ($234 million). For Entergy subsidiaries, nonfuel O&M savings stem from both the merger and the reorganization and restructuring program Entergy implemented in the third quarter of 1994. However, measured total savings in this category for the original Entergy utilities over the first 4 years after the merger ($647 million) are so much greater than estimated merger savings over the first 5 years ($31 million) that it is probable that the estimated merger savings were achieved. Since the measures implemented to achieve these savings are permanent, it is likely that Entergy will realize total estimated merger savings in this category of $673 million over the first 10 years after the merger.

3. Based on the public data reviewed, no conclusion can be made as to whether Entergy will realize its estimated merger savings ($184 million) from the deferral of resource capacity, which was projected to occur over the 1999-2003 timeframe.

4. Recorded costs associated with the merger were about $129.4 million, including $33.5 million of merger transaction costs recorded by Entergy in 1993. Entergy probably also incurred planned capital costs of $65 million, yielding total merger costs of $194.4 million.

5. Although all categories of merger-related costs were not included in Entergy's net merger savings estimates (e.g., capital costs needed to achieve merger savings were estimated separately and pre-1994 incurred costs were not included), based on observed savings over the first 4 years of the merger, it is likely that Entergy will realize its net merger savings estimates in the categories of fuel savings and nonfuel O&M expenses over the first 5 and first 10 years after the merger. (The higher nonfuel O&M merger savings rate being experienced by GSU itself probably will offset higher merger costs than were recorded.)

[119] Op. cit., Entergy Corporation SEC 10-K for 1994, Note 12 to Financial Statements, except for the pre-tax estimate of $70 million associated with the after tax GSU recorded expense of $49 million, which was estimated using an effective tax rate of 30 percent.

[120] Source: Entergy Corporation SEC 10-K for 1996, Note 12 to Financial Statements.

Appendix E

Definitions of Corporate Combinations

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Acquisition: The purchase of one company by another, or the purchase only of certain assets of one company by another. Unlike a hostile takeover, an acquisition is agreeable to both parties. (At times, the term may be used synonymously with merger.)

Active Salvage: A company with serious financial problems is forced to seek a merger, find a buyer, or declare bankruptcy. Also, the selling of assets (perhaps even the entire company) with the aim of salvaging some value for the troubled company.

Divestiture: Involves the sale or trading of assets. Planned divestitures may be undertaken as a part of corporate reorganization to reduce debt, to re-deploy capital, or to eliminate underperforming or noncore lines of business. Divestitures may be required as the result of new or changing regulatory circumstances. Divestitures may also be required as a condition in a pending merger or other combination, for example, to mitigate market power.

Foreign Investment: May be in the form of an acquisition, merger, or joint venture. Domestic companies may invest outside the United States to get into nonregulated businesses as markets privatize. Foreign companies also invest in the United States to gain entry into the large U.S. market and into a stable economic environment.

Hostile Takeover: Acquisition of one company by another despite the opposition of the target company.

Joint Venture: A combination of two or more corporations to cooperate for specific purposes but falling short of a merger. Such arrangements may be rather informal and general or very specific, even limited to a single project or purpose. Joint ventures may involve the formation of a separate company that in turn acquires others and develops new products and services on its own. Joint ventures may be open to others by selling shares (after the initial combination). Joint ventures have been used for decades, particularly in situations where high capital costs or risk are prevalent, such as power plant construction, pipeline construction, and exploration and development of difficult fields such as offshore. Joint ventures have become common among nonregulated subsidiaries and affiliates with the formation of marketing companies in telecommunications, software, and energy management.

Merger (Full): Complete legal joining together of two (or occasionally more) separate companies into a single unit. In legal terms only one entity survives.

Merger (Horizontal): Two similar entities merge to extend geographic coverage or increase market share. Examples are combinations of pipelines or especially local distribution companies.

Merger (Partial): Only certain units of one or both companies are involved in the merger. (For example, Chevron's gas unit merges with NGC. Chevron ends up owning about 25 percent of NGC while NGC operates all of Chevron's gas business.)

Merger (Vertical): May be achieved by combining two companies in different areas of the gas industry or through the combination of two or more entities in the same industry.

Strategic Alliance: Similar to and in many instances the same as joint venture. One type of strategic alliance has recently become popular that involves a typical marketing arrangement wherein one party provides services to another but includes the additional provision of shared savings once certain targets have been achieved. Also used in co-branding.