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Preliminary Economic Profile:

Steam Electric Detailed Study

U.S. Environmental Protection Agency
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Office of Water
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Table of Contents

Introduction

This profile compiles and analyzes economic and operational data for the electric power generating industry. It provides information on the structure and overall performance of the industry and explains important trends that may influence the nature and magnitude of economic impacts that could result from compliance with the steam-electric effluent limitation guidelines.

1 Industry Characteristics

This section presents key characteristics of the electric power industry, including industry sectors, types of generating facilities, ownership, capacity, generation, business size, and geographic distribution. These characteristics define the industry and the subset of the industry subject to potential effluent limitation guidelines. Together with the financial status of the industry discussed in Section 2 below, these industry characteristics are among the key determinants of economic achievability and potential for economic impact as a result of potential environmental regulation.

1.1 Industry Sectors

The electricity business is made up of three major functional service components or sectors: generation, transmission, and distribution. These terms are defined as follows (Beamon, 1998; Joskow, 1997; U.S. DOE, 2004b):

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[1] Electric power is usually produced by a mechanically driven rotary generator called a turbine. Generator drivers, also called prime movers, include gas or diesel internal combustion machines, as well as streams of moving fluid such as wind, water from a hydroelectric dam, or steam from a boiler. Most boilers are heated by direct combustion of fossil or biomass-derived fuels or waste heat from the exhaust of a gas turbine or diesel engine, but heat from nuclear, solar, and geothermal sources is also used. Electric power may also be produced without a generator by using electrochemical, thermoelectric, or photovoltaic (solar) technologies.

- The ***transmission*** sector can be thought of as the interstate highway system of the business – the large, high-voltage power lines that deliver electricity from power plants to local areas. Electricity transmission involves the "transportation" of electricity from power plants to distribution centers using a complex system. Transmission requires: interconnecting and integrating a number of generating facilities into a stable, synchronized, alternating current network; scheduling and dispatching all connected plants to balance the demand and supply of electricity in real time; and managing the system for equipment failures, network constraints, and interaction with other transmission networks.

- The ***distribution*** sector can be thought of as the local delivery system – the relatively low-voltage power lines that bring power to homes and businesses. Electricity distribution relies on a system of wires and transformers along streets and underground to provide electricity to residential, commercial, and industrial consumers. The distribution system

[1] Terms highlighted in ***bold and italic font*** are defined in the Glossary at the end of this document.

involves both the provision of the hardware (e.g., lines, poles, transformers) and a set of retailing functions, such as metering, billing, and various demand management services.

Of the three industry sectors, only electricity generation has the potential to produce effluents and would be subject to steam-electric effluent limitation guidelines. The remainder of this profile will focus on the generation sector of the industry.

1.2 Prime Movers

Electric power plants use a variety of ***prime movers*** to generate electricity. The type of prime mover used at a given plant is determined based on the type of load the plant is designed to serve, the availability of fuels, and energy requirements. Most prime movers use fossil fuels (coal, oil, and natural gas) as an energy source and employ some type of turbine to produce electricity. According to the Department of Energy, the most common prime movers are (U.S. DOE, 2004b):

- ***Steam Turbine:*** "Most of the electricity in the United States is produced in steam turbines. In a fossil-fueled steam turbine, the fuel is burned in a boiler to produce steam. The resulting steam then turns the turbine blades that turn the shaft of the generator to produce electricity. In a nuclear-powered steam turbine, the boiler is replaced by a reactor containing a core of nuclear fuel (primarily enriched uranium). Heat produced in the reactor by fission of the uranium is used to make steam. The steam is then passed through the turbine generator to produce electricity, as in the fossil-fueled steam turbine. Steam-turbine generating units are used primarily to serve the ***base load*** of electric utilities. Fossil-fueled steam-turbine generating units range in size (***nameplate capacity***) from 1 ***megawatt (MW)*** to more than 1,000 megawatts. The size of nuclear-powered steam-turbine generating units in operation today ranges from 75 megawatts to more than 1,400 megawatts."

- ***Gas Turbine:*** "In a gas turbine (combustion-turbine) unit, hot gases produced from the combustion of natural gas and distillate oil in a high-pressure combustion chamber are passed directly through the turbine, which spins the generator to produce electricity. Gas turbines are commonly used to serve the ***peak loads*** of the electric utility. Gas-turbine units can be installed at a variety of site locations, because their size is generally less than 100 megawatts. Gas-turbine units also have a quick startup time, compared with steam-turbine units. As a result, gas-turbine units are suitable for peakload, emergency, and reserve-power requirements. The gas turbine, as is typical with peaking units, has a lower efficiency than the steam turbine used for baseload power."

- ***Combined-Cycle Unit:*** "The efficiency of the gas turbine is increased when coupled with a steam turbine in a combined-cycle operation. In this operation, hot gases (which have already been used to spin one turbine generator) are moved to a waste-heat recovery steam boiler where the water is heated to produce steam that, in turn, produces electricity by running a second steam-turbine generator. In this way, two generators produce electricity from one initial fuel input. All or part of the heat required to produce steam may come from the exhaust of the gas turbine. Thus, the steam-turbine generator may be supplementarily fired in addition to the waste heat. Combined-cycle generating units generally serve ***intermediate loads***."

- ***Internal Combustion Engine:*** "These prime movers have one or more cylinders in which the combustion of fuel takes place. The engine, which is connected to the shaft of the generator, provides the mechanical energy to drive the generator to produce electricity. Internal-combustion (or diesel) generators can be easily transported, can be installed upon short notice, and can begin producing electricity nearly at the moment they start. Thus, like gas turbines, they are usually operated during periods of high demand for electricity. They are generally about 5 megawatts in size."

- ***Hydroelectric Generating Unit:*** "Hydroelectric power is the result of a process in which flowing water is used to spin a turbine connected to a generator. The two basic types of hydroelectric systems are those based on falling water and natural river current. In the first system, water accumulates in reservoirs created by the use of dams. This water then falls through conduits (penstocks) and applies pressure against the turbine blades to drive the generator to produce electricity. In the second system, called a run-of-the-river system, the force of the river current (rather than falling water) applies pressure to the turbine blades to produce electricity. Since run-of-the-river systems do not usually have reservoirs and cannot store substantial quantities of water, power production from this type of system depends on seasonal changes and stream flow. These conventional hydroelectric generating units range in size from less than 1 megawatt to 700 megawatts. Because of their ability to start quickly and make rapid changes in power output, hydroelectric generating units are suitable for serving peak loads and providing spinning reserve power, as well as serving baseload requirements. Another kind of hydroelectric power generation is the pumped storage hydroelectric system. Pumped storage hydroelectric plants use the same principle for generation of power as the conventional hydroelectric operations based on falling water and river current. However, in a pumped storage operation, low-cost off-peak energy is used to pump water to an upper reservoir where it is stored as potential energy. The water is then released to flow back down through the turbine generator to produce electricity during periods of high demand for electricity."

In addition, there are a number of other prime movers:

- ***Other Prime Movers:*** "Other methods of electric power generation, which presently contribute only small amounts to total power production, have potential for expansion. These include geothermal, solar, wind, and biomass (wood, municipal solid waste, agricultural waste, etc.). Geothermal power comes from heat energy buried beneath the surface of the earth. Although most of this heat is at depths beyond current drilling methods, in some areas of the country, magma – the molten matter under the earth's crust from which igneous rock is formed by cooling – flows close enough to the surface of the earth to produce steam. That steam can then be harnessed for use in conventional steam-turbine plants. Solar power is derived from the energy (both light and heat) of the sun. Photovoltaic conversion generates electric power directly from the light of the sun; whereas, solar-thermal electric generators use the heat from the sun to produce steam to drive turbines. Wind power is derived from the conversion of the energy contained in wind into electricity. A wind turbine is similar to a typical wind mill. However, because of the intermittent nature of sunlight and wind, high capacity utilization factors cannot be achieved for these plants. Several electric utilities have incorporated wood and waste (for example, municipal waste, corn cobs, and oats) as energy sources for producing electricity at their power plants. These sources replace fossil fuels in the boiler. The combustion of wood and waste creates steam that is typically used in conventional steam-electric plants."

The potential steam-electric effluent limitation guidelines are only relevant for electric generators that use a steam-electric generating cycle. This profile will, therefore, differentiate between steam-electric and other prime movers. EPA identified steam-electric prime movers using data collected by the EIA (U.S. DOE, 2003b).[2] For this profile, the following prime movers, including both steam turbines and combined-cycle technologies, are classified as steam electric:

- Steam Turbine, including nuclear, geothermal, and solar steam (not including combined cycle),
- Combined-Cycle Steam Part,
- Combined-Cycle Combustion Turbine Part,
- Combined-Cycle Single Shaft (combustion turbine and steam turbine share a single generator), and
- Combined-Cycle Total Unit (used only for plants/generators that are in the planning stage).

Table 1 provides data on the number of existing power plants, by prime mover and regulatory status. This table includes all plants that have at least one non-retired unit and that submitted Form EIA-860 (Annual Electric Generator Report) for reporting year 2003. For the purpose of this analysis, plants were classified as "steam turbine" or "combined-cycle" if they have at least one generating unit of that type. Plants that do not have any steam electric units were classified under the prime mover type that accounts for the largest share of the plant's total generating capacity.

Table 1: Number of Existing Utility and Nonutility Plants by Prime Mover in 2003

Prime Mover	Number of Plants		
	Utility[a]	Nonutility[a]	Total
Steam Turbine	603	868	1,471
Combined-Cycle	82	331	413
Gas Turbine	356	454	810
Internal Combustion	603	362	965
Hydroelectric	899	494	1,393
Other	24	178	202
Total	**2,567**	**2,687**	**5,254**

[a] See definition of utility and nonutility in Section 1.3 below.

Source: U.S. DOE, 2003b.

[2] Form EIA-860 (Annual Electric Generator Report) collects data used to create an annual inventory of all units, plants, and utilities. The data collected includes: type of prime mover; nameplate rating; energy source; year of initial commercial operation; operating status; water source, NERC region, and NAICS code.

1.3 Ownership

The U.S. electric power industry consists of two broad categories of firms that own and operate electric generating plants: traditional electric utilities and nontraditional participants. Generally, they can be defined as follows (adapted from U.S. DOE, 2003a):

1.3.1 Traditional electric utilities

Traditional electric ***utilities*** are regulated and traditionally vertically integrated entities. They all have distribution facilities for delivery of electric energy for use primarily by the public, but they may or may not generate electricity. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system serving retail customers. Electric utilities can be further divided into four major ownership categories: investor-owned utilities, publicly-owned utilities, rural electric cooperatives, and Federal utilities. Each category is discussed below (U.S. DOE, 2004b).

- **Investor-owned utilities (IOUs)** are privately owned entities. Like all private businesses, investor-owned electric utilities have the fundamental objective of producing a return for their investors. These utilities either distribute profits to stockholders as dividends or reinvest the profits. Investor-owned electric utilities are granted service monopolies in certain geographic areas and are obliged to serve all consumers. As franchised monopolies, these utilities are regulated and required to charge reasonable prices, to charge comparable prices to similar classifications of consumers, and to give consumers access to services under similar conditions. Most investor-owned electric utilities are operating companies that provide basic services for the generation, transmission, and distribution of electricity. In 2003, IOUs operated 1,151 facilities, which accounted for approximately 39% of all U.S. electric generation capacity (U.S. DOE, 2003b).

- **Publicly-owned utilities** are nonprofit local government agencies established to provide service to their communities and nearby consumers at cost. Publicly owned electric utilities include municipalities, State authorities, and political subdivisions (e.g., public power districts, irrigation projects, and other State agencies established to serve their local municipalities or nearby communities). Excess funds or "profits" from the operation of these utilities are put toward reducing rates, increasing facility efficiency and capacity, and funding community programs and local government budgets. Most municipal utilities are nongenerators engaging solely in the purchase of wholesale electricity for resale and distribution. The larger municipal utilities, however, generate and transmit electricity as well. In general, publicly-owned utilities have access to tax-free financing and do not pay certain taxes or dividends, giving them some cost advantages over IOUs. In 2003, municipalities operated 817 facilities (4.6% of U.S. capacity), States operated 90 facilities (1.8% of U.S. capacity), and political subdivisions operated 135 facilities (2.1% of U.S. capacity) (U.S. DOE, 2003b).

- **Cooperative utilities** are member-owned entities created to provide electricity to those members. These utilities, established under the Rural Electrification Act of 1936, operate in rural areas with low concentrations of consumers because these areas historically have been viewed as uneconomical operations for IOUs. The National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank of Cooperatives are important sources of financing for these utilities. Cooperatives operate in

47 States and are incorporated under State laws. In 2003, rural electric cooperatives operated 174 generating facilities and accounted for approximately 3.3% of all U.S. electric generation capacity (U.S. DOE, 2003b).

- **Federal electric utilities** are part of several agencies in the U.S. Government: the Army Corps of Engineers (Department of Defense), the Bureau of Indian Affairs and the Bureau of Reclamation (Department of the Interior), the International Boundary and Water Commission (Department of State), the Power Marketing Administrations (Department of Energy), and the Tennessee Valley Authority (TVA). Three Federal agencies operate generating facilities: TVA, the largest Federal producer; the U.S. Army Corps of Engineers; and the U.S. Bureau of Reclamation. In 2003, Federal electric utilities operated 198 facilities, accounting for 6.8% of total U.S. electric generation capacity (U.S. DOE, 2003b).

Traditional electric utilities are hereafter referred to as "utilities".

1.3.2 Nontraditional participants

Nontraditional participants are unregulated entities and include energy service providers, ***power marketers***, independent power producers (IPPs), and combined heat and power plants (CHPs, formerly referred to as cogenerators). IPPs own or operate facilities whose primary business is to produce electricity for wholesale to other entities who provide electricity to final customers in retail markets; IPPs are not aligned with distribution facilities. CHPs are plants designed to produce both heat and electricity from a single heat source. CHPs can be independent power producers, or industrial or commercial establishments.

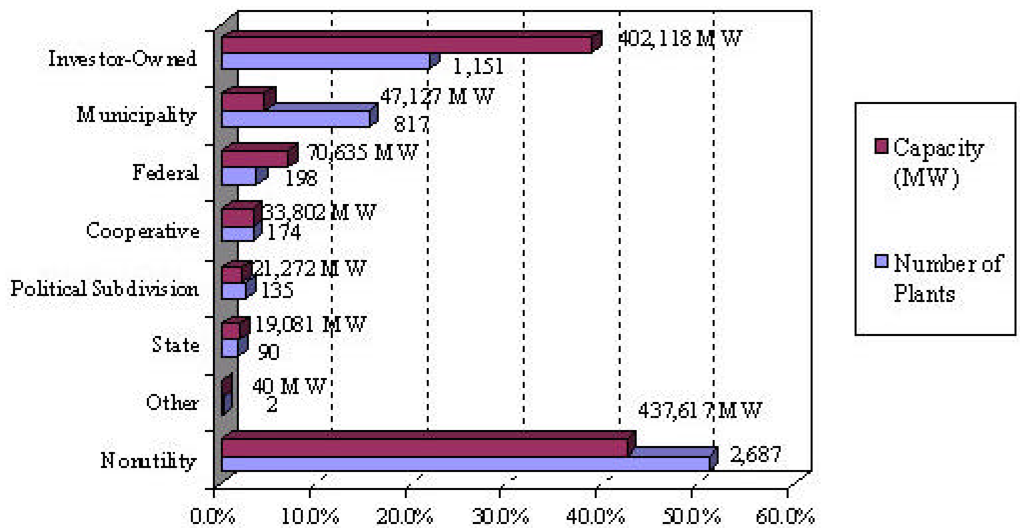
With the on-set of industry deregulation in many states, a new class of unregulated power producers has emerged.[3] In the first states that have implemented retail competition (e.g., California, Massachusetts, New York, Maine, Rhode Island), vertically integrated utilities have been encouraged or required to divest substantially all of their generating assets. In other states (e.g., Pennsylvania, Illinois, Maryland, Ohio, Texas, New Jersey), retail competition programs have permitted utilities to retain their generating assets but have required them to transfer these assets into separate unregulated wholesale power affiliates within a holding company structure. Both divested and transferred power plants are no longer subject to rate regulation but, like other nontraditional participants, now operate in competitive markets. (Joskow, 2003)

Nontraditional industry participants and entities owning divested, transferred, or independently constructed power generating assets are hereafter referred to as "***nonutilities***". In 2003, nonutilities operated 2,687 facilities, accounting for 42.4% of total U.S. electric generation capacity (U.S. DOE, 2003b).

Figure 1 presents the number of generating facilities and their capacity in 2003, by type of ownership. The horizontal axis also presents the percentage of the U.S. total that each type represents. This figure is based on data for all plants that have at least one non-retired unit and that submitted Form EIA-860 in 2003. The graphic shows that nonutilities account for the largest percentage of facilities (2,687, or approximately 51%) and represent 42% of total U.S. generating capacity. Investor-owned utilities operate the second largest number of facilities (1,151, or approximately 22%) and account for 39% of total U.S. capacity.

[3] For more information on industry deregulation, see Section 3.1 below.

Figure 1: Distribution of Facilities and Capacity by Ownership Type in 2003



Source: U.S. DOE, 2003b.

1.4 Generating Capacity

Utilities own and operate the majority of the generating capacity in the United States (57.7% in 2003). Of the remaining 42.3% capacity owned by nonutilities, 34.7% are owned by independent power producers and 7.6% by combined heat and power plants. Industry deregulation has led to a substantial increase in nonutility capacity over the past few years, as a result of both new plant construction by independent power producers and plant divestitures by investor-owned utilities. Nonutility capacity increased by 550% between 1994 and 2003, compared with a decrease in utility capacity of 22% over the same time period (U.S. DOE, 2004a).

Capacity

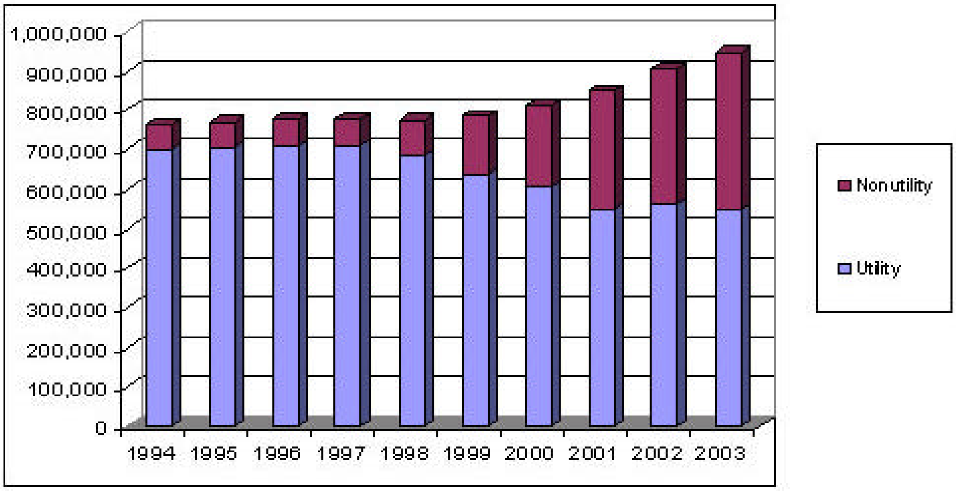
The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW).

Nameplate capacity is the full-load continuous output rating of the generating unit under specified conditions, as designated by the manufacturer.

U.S. DOE, 2004b

Figure 2 shows the growth in utility and nonutility capacity between 1994 and 2003. During the mid-1990s, very little new capacity was added because of perceived excess generating capacity and uncertainty about the direction of industry restructuring activities (Joskow, 2003). However, with new FERC regulations aimed at fostering wholesale and retail competition and with rising wholesale prices, many new merchant plants were announced and constructed, leading to a total capacity of almost 950,000 MW in 2003, an increase of almost 21% since 1999 (Joskow, 2003; U.S. DOE, 2004a). This trend is not expected to continue, however, as the booming merchant power industry has come under severe pressure due to abundant generating capacity in almost all regions of the country. Many firms in the merchant generating sector now find themselves in a difficult financial situation, and many planned new generating plants are being postponed indefinitely or cancelled (Joskow, 2003).

Figure 2: Net Summer Capacity, 1994 to 2003 (MW)



Source: U.S. DOE, 2004a.

1.5 Electricity Generation

In 2003, total net electricity generation in the U.S. was 3,883 million MWh, an increase of 20% since 1994. In response to industry deregulation efforts in many states, many utilities have divested their generating assets and new merchant plants have been built; this has resulted in a decrease in utilities' share of total electricity generation from 89% in 1998 to 63% in 1994 (U.S. DOE, 2004a). However, this trend is not expected to continue with the recent slow-down in deregulation activities in several states.

Table 2 shows the change in net generation between 1994 and 2003, by energy source and ownership type.

Measures of Generation

The production of electricity is referred to as generation and is measured in ***kilowatthours (kWh)***. Generation can be measured as:

Gross generation: The total amount of power produced by an electric power plant.

Net generation: Power available to the transmission system beyond that needed to operate plant equipment. For example, around 7% of electricity generated by steam electric units is used to operate equipment.

Electricity available to consumers: Power available for sale to customers. Approximately 8% to 9% of net generation is lost during the transmission and distribution process.

U.S. DOE, 2004b

Table 2: Net Generation by Energy Source and Ownership Type, 1994 to 2003 (million MWh)

Energy Source	Utilities			Nonutilities			Total		
	1994	2003	% Change	1994	2003	% Change	1994	2003	% Change
Coal	1,635	1,500	-8.3%	55	473	757.7%	1,691	1,974	16.7%
Nuclear	640	459	-28.4%	-	305	n/a	640	764	19.3%
Natural Gas	291	187	-35.8%	169	463	173.8%	460	650	41.2%
Hydropower	244	242	-0.7%	13	25	92.9%	257	267	4.1%
Petroleum	91	70	-23.2%	15	49	232.8%	106	119	12.8%
Renewables [a]	9	4	-55.9%	68	83	23.5%	77	87	14.2%
Other Gases	-	0.2	n/a	13	15.4	15.3%	13	15.6	17.1%
Other [b]	-	-	n/a	4	6	66.9%	4	6	66.9%
Total	**2,911**	**2,462**	**-15.4%**	**337**	**1,421**	**321.9%**	**3,248**	**3,883**	**19.6%**

[a] *Renewables include solar, wind, wood, biomass, and geothermal energy sources.*

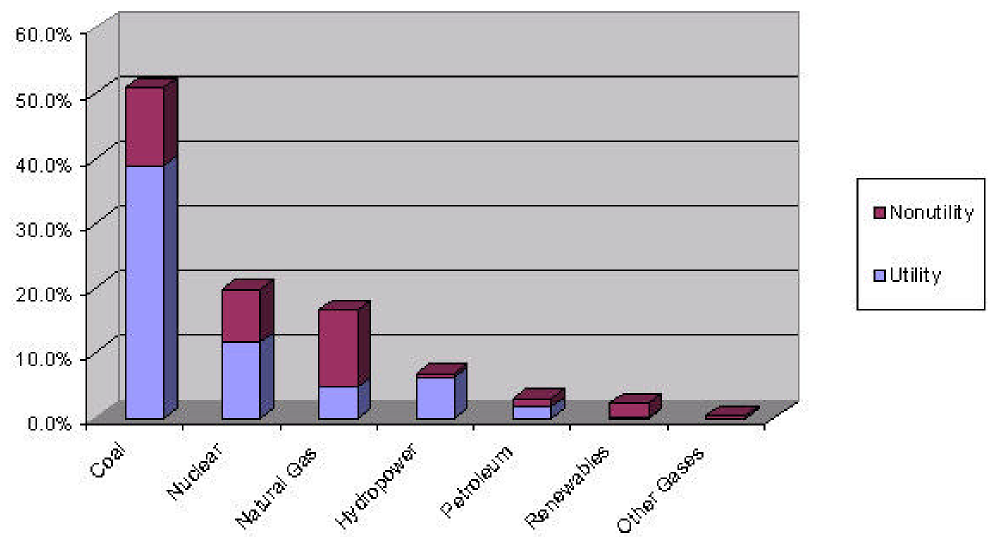
[b] *Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.*

Source: U.S. DOE, 2004a.

As shown in Table 2, different fuel source categories experienced different growth rates over the 10-year period 1994 to 2003. Natural gas generation grew the fastest among the primary fuel source categories, increasing by 41%. Nuclear generation increased by 19%, coal generation increased by 17%, and generation from renewable energy sources increased by 14%. Hydropower showed the slowest growth with only 4%.

Figure 3 shows the distribution of net generation by primary fuel source, for utilities and nonutilities. Coal-fired plants continued to account for the largest share of electricity generation in 2003, with 51% of total generation, followed by nuclear plants with 20%, and natural gas plants with 17% of total generation. Coal accounts for 61% of all utility generation and 33% of all nonutility generation. The second major fuel source for nonutilities is natural gas, which also accounted for 33% of total nonutility generation in 2003.

Figure 3: Percentage of Electricity Generation by Primary Fuel Source in 2003



Source: U.S. DOE, 2004a.

1.6 Business Size

An important component of an economic analysis of effluent limitation guidelines is consideration of potential adverse impacts on small entities. This section characterizes the electric power industry in terms of entity size, by type of ownership. For this preliminary analysis, entity size was determined for all utilities and nonutilities that reported electricity generation in the 2003 Form EIA-861.[4] The determination is based on an electricity sales threshold of 4 million MWh.[5]

Table 3 presents the number of entities and their electricity sales for the industry as a whole and for those entities classified as small for this preliminary analysis. The table shows that the majority of entities in the electric power industry, almost 90%, are small according to the size definition used in this analysis. However, these small entities only account for approximately 14% of total electricity sales. The size distribution differs substantially among the different ownership types: almost 97% of all municipalities but only 34% of all investor-owned utilities are classified as small. These account for 48% and 1% of total electricity sales in their respective ownership classes. Entities owned by a state or Federal government are by definition considered large.

[4] Nonutilities exclude 379 entities that do not sell any power; these are classified as "on-site generators".

[5] It should be noted that the size determination for small entity analyses is generally made at the highest level of domestic ownership. Some investor-owned utilities and nonutilities are part of a holding company structure, which is a higher level than the entity which reports on Form EIA-861. An entity that is small at the Form EIA-861 reporting level might not be small at the holding company level. As a result, the number of small investor-owned utilities and nonutilities and their electricity sales might be overestimated. In addition, the official SBA size threshold for publicly-owned companies, including municipalities and political subdivisions, is 50,000 people served, not 4 million MWh. Publicly-owned utilities that are small using the 4 million MWh threshold might not be small using a 50,000 people served threshold, and vice versa. As a result, the number of small municipalities and political subdivisions and their electricity sales might be over- or underestimated.

Table 3: Number of Entities and Electricity Sales by Entity Size and Owner Type, 2003[a]						
Owner Type	**Number of Entities**			**Electricity Sales (GWh)[b]**		
	Total	**Small**	**Small as % of Total**	**Total**	**Small**	**Small as % of Total**
Investor-Owned[c]	153	52	34.0%	2,798,193	31,182	1.1%
Municipality[d]	523	506	96.7%	315,195	150,651	47.8%
State	19	-	0.0%	149,378	-	0.0%
Political Subdivision[d]	49	39	79.6%	175,290	50,726	28.9%
Cooperative	80	61	76.3%	296,964	64,331	21.7%
Federal	8	-	0.0%	299,677	-	0.0%
Subtotal Utility	832	658	79.1%	4,034,698	296,890	7.4%
Nonutility[c,e]	1,251	1,195	95.5%	1,210,286	451,674	37.3%
Grand Total	**2,083**	**1,853**	**89.0%**	**5,244,984**	**748,564**	**14.3%**

[a] The entity size determination for this analysis is made at the Form EIA-861 reporting level and is based on an electricity sales threshold of 4 million MWh. The analysis excludes entities that do generate electricity, e.g., transmission and distribution utilities.

[b] Electricity sales include both wholesale and resale sales.

[c] For investor-owned utilities and nonutilities, the number of small entities and their electricity sales might be overestimated because investor-owned utilities and nonutilities are often part of a holding company structure; therefore, the Form EIA-861 reporting level might not be the highest level of domestic ownership for these entities.

[d] For publicly-owned companies, the number of small entities and their electricity sales might be over- or underestimated because the SBA size threshold for publicly-owned companies is 50,000 people served; this threshold might result in different size classification than the 4 million MWh used in this analysis.

[e] Nonutilities exclude 379 entities that do not sell any power; these are classified as "on-site generators".

Source: U.S. DOE, 2003c.

1.7 Geographic Distribution

Electricity is a commodity that cannot be stored or easily transported over long distances. As a result, the geographic distribution of power plants is of primary importance to ensure a reliable supply of electricity to all customers. The U.S. bulk power system is composed of three major networks, or power grids:

- the *Eastern Interconnected System*, consisting of one third of the U.S., from the East Coast to East of the Missouri River;
- the *Western Interconnected System*, West of the Missouri River, including the Southwest and areas West of the Rocky Mountains; and
- the *Texas Interconnected System*, the smallest of the three, consisting of the majority of Texas.

The Texas system is not connected with the other two systems, but the other two have limited interconnection to each other. The Eastern and Western systems are integrated with or have links to the Canadian grid system. The Western and Texas systems have links with Mexico.

These major networks contain extra-high voltage connections that allow for power transactions from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system ***reliability***. Reliability refers to the ability of power systems to meet the demands of consumers at any given time. Efforts to enhance reliability reduce the chances of power outages.

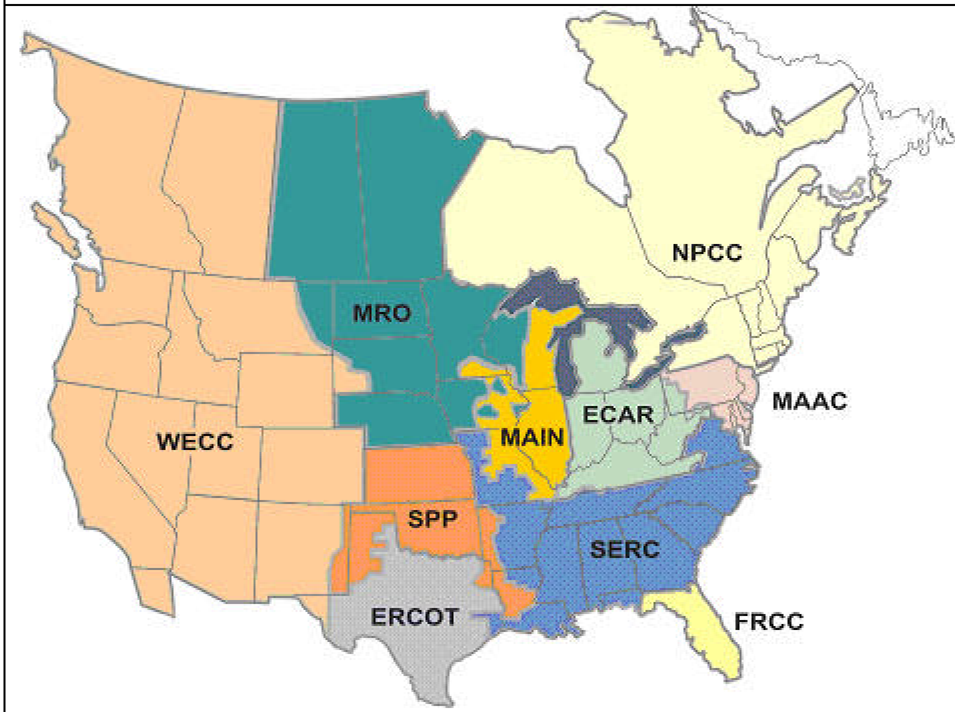
The North American Electric Reliability Council (NERC) is responsible for the overall reliability, planning, and coordination of the power grids. This voluntary organization was formed in 1968 by electric utilities, following a 1965 blackout in the Northeast. NERC is organized into ten regional councils that cover the 48 contiguous States, and affiliated councils that cover Hawaii, part of Alaska, and portions of Canada and Mexico. These regional councils are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service. Each NERC region deals with electricity reliability issues in its region, based on available capacity and transmission constraints. The councils also aid in the exchange of information among member utilities in each region and among regions. Service areas of the member utilities determine the boundaries of the NERC regions. Though limited by the larger bulk power grids described above, NERC regions do not necessarily follow any State boundaries. Historically, almost all wholesale trade was within the NERC regions, but utilities are expanding wholesale trade beyond those traditional boundaries (U.S. DOE, 2004b).

Figure 4 below provides a map of the NERC regions, which include:

- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas, Inc.
- FRCC – Florida Reliability Coordinating Council
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnected Network, Inc.
- MRO – Midwest Reliability Organization (formerly the Mid-Continent Area Power Pool, MAPP)
- NPCC – Northeast Power Coordinating Council
- SERC – Southeastern Electric Reliability Council
- SPP – Southwest Power Pool, Inc.
- WECC – Western Electricity Coordinating Council (formerly the Western Systems Coordinating Council, WSCC)

Alaska and Hawaii are not shown in Figure 4. Part of Alaska is covered by the Alaska Systems Coordinating Council (ASCC), an affiliate NERC member. The State of Hawaii also has its own reliability authority (HICC).

Figure 4: North American Electric Reliability Council (NERC) Regions



Source: NERC, 2005.

Table 4 shows the distribution of all existing plants and capacity by NERC region. The table shows that 1,357 plants, equal to 26% of all facilities in the U.S., are located in the Western Electric Coordinating Council (WECC). However, these plants account for only 17% of total national capacity. Conversely, only 13% of generating plants are located in the Southeastern Electric Reliability Council (SERC), yet these plants account for 22% of total national capacity.

Table 4: Distribution of Existing Plants and Capacity by NERC Region in 2003

NERC Region	Plants		Capacity	
	Number	% of Total	Total MW	% of Total
ASCC	115	2.2%	2,126	0.2%
ECAR	486	9.3%	144,614	14.0%
ERCOT	234	4.5%	94,901	9.2%
FRCC	132	2.5%	53,367	5.2%
HICC	34	0.6%	2,508	0.2%
MAAC	266	5.1%	73,588	7.1%
MAIN	420	8.0%	77,791	7.5%
MRO	470	8.9%	37,844	3.7%
NPCC	711	13.5%	76,145	7.4%
SERC	701	13.3%	231,023	22.4%
SPP	328	6.2%	63,533	6.2%
WECC	1,357	25.8%	174,252	16.9%
Total	**5,254**	**100.0%**	**1,031,692**	**100.0%**

Source: U.S. DOE, 2003b.

2 Financial Status and Trends

This section presents information on the financial status of the electric power industry and trends over the past ten years.

2.1 Sales and Prices

In 2003, 3,488 million MWhs of electricity were sold in the United States. This represents a 19% increase in total sales between 1994 and 2003. The majority of sales, 37% in 2003, were to residential customers. Commercial and industrial end users accounted for an additional 34% and 29% of sales, respectively. Sales to the transportation sector were reported for the first time in 2003. Those sales were previously included in the customer class "other." Certain sales in the "other" category were reclassified as "commercial" in 2003, accounting for almost all of the increase in that sector. Table 5 shows sales by ultimate customer class between 1994 and 2003.

Table 5: Sales to Ultimate Customers (million MWhs)

	All Sectors	Residential	Commercial	Industrial	Transportation	Other
1994	2,935	1,008	820	1,008	n/a	98
1995	3,013	1,043	863	1,013	n/a	95
1996	3,101	1,083	887	1,034	n/a	98
1997	3,146	1,076	929	1,038	n/a	103
1998	3,264	1,130	979	1,051	n/a	104
1999	3,312	1,145	1,002	1,058	n/a	107
2000	3,421	1,192	1,055	1,064	n/a	109
2001	3,370	1,203	1,089	964	n/a	114
2002	3,463	1,267	1,116	972	n/a	107
2003	3,488	1,273	1,200	1,008	7	n/a
Total Growth	**18.9%**	**26.3%**	**46.3%**	**0.0%**	**n/a**	**n/a**
Annual Comp. Growth	**1.9%**	**2.6%**	**4.3%**	**0.0%**	**n/a**	**n/a**

Source: U.S. DOE, 2004a.

All customer classes experienced a decrease in real electricity prices between 1994 and 2003 (adjusted using the gross domestic product deflator). However, after a 9-year trend of general decline, electricity prices rose in all but one sector between 2002 and 2003 due to an increase in the average cost for each of the three major fossil fuels used for electricity generation. The average electricity price for all sectors was 7.58 cents per kilowatt hour in 2003, 9% lower than in 1994 and 1% higher than in 2002. The residential sector had the highest rates of all customer classes, 8.88 cents/kWh in 2003, compared to 5.24 cents/kWh for the industrial sector. This rate differential is partially explained by the higher per unit cost of delivering electricity to households. Table 6 shows rates by customer class between 1994 and 2003.

Table 6: Average Retail Price (cents/kWh; 2004 $)						
	All Sectors	**Residential**	**Commercial**	**Industrial**	**Transportation**	**Other**
1994	8.29	10.05	9.27	5.72	n/a	8.20
1995	8.10	9.87	9.04	5.48	n/a	8.08
1996	7.91	9.64	8.81	5.31	n/a	7.97
1997	7.77	9.56	8.61	5.14	n/a	7.84
1998	7.56	9.27	8.31	5.03	n/a	7.44
1999	7.34	9.02	8.03	4.90	n/a	7.02
2000	7.37	8.92	8.04	5.02	n/a	7.10
2001	7.74	9.11	8.38	5.33	n/a	7.43
2002	7.50	8.80	8.17	5.07	n/a	7.00
2003	7.58	8.88	8.15	5.24	7.74	n/a
Total Growth	**-8.6%**	**-11.6%**	**-12.1%**	**-8.4%**	**n/a**	**n/a**
Annual Comp. Growth	**-1.0%**	**-1.4%**	**-1.4%**	**-1.0%**	**n/a**	**n/a**
Source: U.S. DOE, 2004a.						

2.2 Operating Revenues and Expenses

Table 7 shows operating revenue (including sales to ultimate customers, sales for resale, and other electric income) and operating expense trends between 1994 and 2003 for each of the principal utility ownership classes. Over the period, each ownership class experienced fluctuations in both operating revenues and operating expenses. Operating revenues for investor-owned utilities decreased slightly over the 10-year period – compared to increases in the other ownership classes – potentially as a result of a reduction in their generating capacity due to the divesture of generating assets in States that have introduced industry restructuring measures. Operating expenses increased for all ownership classes, with the highest increase in the publicly-owned utility sector (35.3%). All ownership classes, except for federally-owned utilities, experienced substantial reductions in operating income between 1994 and 2003.

Major investor-owned utilities are the largest utility class, receiving 75% of total 2003 utility revenues.[6] Major federally-owned utilities account for the smallest share of total operating revenues (4% in 2003) but are consistently the most profitable utility class, with an operating income margin (operating income as a percentage of revenues) of between 19.6% and 32.1% during the 10-year period. All utility classes have experienced a decline in their income as a percentage of their revenues over the 10-year period, and most have also experienced small increases in their expenses as a percentage of their revenues. This might be a result of reduced rates mandated in deregulation programs, increased competition from nonutilities, or the divesture of higher margin business segments.

[6] A utility is classified as "major" and included in the statistics presented in Table 7 is it meets or exceeds certain minimum capacity, electricity generation, or electricity sales requirements.

Table 7: Revenue and Expense Statistics for 1994 - 2003 (2004 $; million)											
	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	% Change
Major Investor Owned Utilities											
Operating Revenues	235,378	234,988	239,257	243,989	244,782	236,850	254,721	282,777	228,125	231,006	-1.9%
Operating Expenses	196,914	194,275	200,577	207,363	209,242	201,568	227,648	248,607	196,261	201,630	2.4%
Operating Income	38,463	40,714	38,680	36,625	35,540	35,282	27,072	34,170	31,864	29,376	-23.6%
Expenses as % of Revenues	83.7%	82.7%	83.8%	85.0%	85.5%	85.1%	89.4%	87.9%	86.0%	87.3%	4.3%
Income as % of Revenues	16.3%	17.3%	16.2%	15.0%	14.5%	14.9%	10.6%	12.1%	14.0%	12.7%	-22.2%
Major Publicly Owned Utilities (with Generation)											
Operating Revenues	27,901	27,584	27,917	28,810	29,345	29,603	34,466	40,196	34,081	34,622	24.1%
Operating Expenses	22,364	22,279	22,009	23,170	23,426	23,528	28,406	34,658	29,778	30,263	35.3%
Operating Income	5,538	5,305	5,908	5,640	5,918	6,075	6,059	5,537	4,303	4,358	-21.3%
Expenses as % of Revenues	80.2%	80.8%	78.8%	80.4%	79.8%	79.5%	82.4%	86.2%	87.4%	87.4%	9.1%
Income as % of Revenues	19.8%	19.2%	21.2%	19.6%	20.2%	20.5%	17.6%	13.8%	12.6%	12.6%	-36.6%
Major Federally Owned Utilities											
Operating Revenues	10,255	10,274	10,474	10,020	10,973	11,265	11,565	13,168	11,927	12,047	17.5%
Operating Expenses	7,558	7,241	7,369	6,805	7,965	8,599	8,809	10,584	9,010	8,948	18.4%
Operating Income	2,697	3,033	3,105	3,215	3,008	2,666	2,756	2,584	2,917	3,099	14.9%
Expenses as % of Revenues	73.7%	70.5%	70.4%	67.9%	72.6%	76.3%	76.2%	80.4%	75.5%	74.3%	0.8%
Income as % of Revenues	26.3%	29.5%	29.6%	32.1%	27.4%	23.7%	23.8%	19.6%	24.5%	25.7%	-2.2%
Major Cooperative Borrower Owned Utilities											
Operating Revenues	28,513	28,919	28,168	26,455	26,913	26,348	27,740	27,966	28,551	29,845	4.7%
Operating Expenses	25,174	25,549	26,697	23,499	23,811	23,538	24,875	25,118	25,539	26,918	6.9%
Operating Income	3,339	3,370	3,312	2,956	3,101	2,810	2,865	2,850	3,012	2,928	-12.3%
Expenses as % of Revenues	88.3%	88.3%	94.8%	88.8%	88.5%	89.3%	89.7%	89.8%	89.4%	90.2%	2.2%
Income as % of Revenues	11.7%	11.7%	11.8%	11.2%	11.5%	10.7%	10.3%	10.2%	10.6%	9.8%	-16.2%
Source: U.S. DOE, 2004a.											

2.3 Measures of Financial Performance and Condition

This section presents trends in financial performance and condition for the utility sector (by geographic region) and a segment of the nonutility sector. Financial performance measures provide an indication of how successful an industry is in generating income in relation to invested capital or in relation to total sales. The financial performance measures used in this analysis are return on shareholders equity, return on total capital, and net profit margin. Financial condition measures provide an indication of an industry's ability to meet financial obligations on time and to withstand fluctuations in operating profits. One important measure of financial condition is the level of debt in relation to a business' total assets. All else being equal, increased debt levels signal a riskier financial structure and indicate whether fluctuations in financial performance are more likely to create severe financial stress for an industry or business.

Measures of financial performance and condition used in this section were derived using data from Value Line. The data for electric utilities are regional aggregates developed by Value Line and include 70 firms. Of these, 10 firms do not generate electricity and would not be subject to potential steam-electric effluent limitation guidelines; however, these 10 firms are included in the data presented in Table 8. The data for nonutilities were developed using revenue-weighted data for six of 24 firms reported in Value Line. The 18 firms not included in Table 8 are not engaged in electricity generation and would not be subject to this rule.

Table 8 shows a general decline, with fluctuations, in the financial performance measures over the 10-year period. In particular, the net profit margin for the electric utility sectors experienced a noticeable decline starting with the introduction of industry deregulation in many States. Debt-to-asset ratios in the utility sectors have fluctuated without a clear trend. In the nonutility sector, on the other hand, this measure has improved over the 10-year period, albeit with fluctuations. The observed change is partially the result of a significant change in the firm composition and total size of the nonutility sector between 1993 and 1997; beginning 1998, firm composition and size of the nonutility sector and its debt-to-asset ratios stabilize.[7]

The measures in Table 8 also exhibit signs of the California energy crisis in 2000 and 2001. A number of firms, including PG&E and Edison either filed for bankruptcy or asked for governmental relief during this time. As a result, the western region posted negative results for both return on total capital and net profit margin in 2000. Return on shareholders' equity was not reported during that year.

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[7] The low debt-to-asset ratio in the nonutility sector in 2001 is the result of one firm with a significantly lower ratio reporting in this sector for the first time.

Table 8: Measures of Financial Performance and Condition

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Return on Shareholders' Equity										
Electric Utility - Central	10.7%	9.8%	11.1%	11.1%	10.0%	10.2%	10.0%	9.3%	9.6%	9.4%
Electric Utility - East	11.4%	11.1%	11.4%	10.9%	10.2%	11.0%	13.3%	11.1%	12.8%	11.1%
Electric Utility - West	11.0%	11.6%	12.2%	10.9%	9.9%	10.3%	10.4%	-	13.7%	3.7%
Nonutility	15.5%	14.0%	12.5%	13.1%	11.8%	14.5%	7.7%	12.3%[a]	11.9%	4.4%
Return on Total Capital										
Electric Utility - Central	7.3%	6.9%	7.4%	7.4%	6.9%	6.7%	6.5%	5.8%	6.0%	5.7%
Electric Utility - East	7.9%	7.7%	7.9%	7.7%	7.0%	7.7%	8.6%	7.0%	7.4%	6.5%
Electric Utility - West	7.3%	7.6%	8.0%	7.3%	6.6%	7.0%	6.4%	-2.5%	7.7%	4.3%
Nonutility	6.1%	6.1%	6.0%	6.0%	5.3%	6.4%	3.5%	4.6%	6.9%	4.0%
Net Profit Margin										
Electric Utility - Central	11.1%	9.7%	10.4%	9.5%	7.3%	6.0%	5.7%	3.9%	2.8%	4.9%
Electric Utility - East	11.5%	11.4%	11.5%	10.7%	8.7%	9.2%	9.1%	6.4%	6.7%	8.4%
Electric Utility - West	9.7%	10.2%	11.3%	9.8%	7.2%	5.8%	5.5%	-3.9%	4.6%	2.0%
Nonutility	5.4%	6.3%	5.7%	6.8%	8.7%	9.5%	8.5%	9.4%	3.8%	3.4%
Debt to Asset										
Electric Utility - Central	33.5%	32.6%	33.3%	32.4%	31.8%	33.1%	33.3%	29.7%	31.1%	35.3%
Electric Utility - East	32.0%	31.6%	30.5%	29.5%	30.5%	28.8%	29.5%	29.2%	33.6%	35.4%
Electric Utility - West	33.2%	31.1%	30.9%	31.2%	30.7%	27.9%	30.5%	27.3%	31.7%	27.2%
Nonutility	60.2%	56.6%	55.4%	54.2%	52.0%	49.0%	51.7%	54.8%	37.0%	49.9%

a An outlier value for one of the firms, resulting from the sale of one of its units, was removed during this year.
Source: Value Line, 2004.

Given the tumultuous business environment during the early years of industry deregulation, the time trends presented in Table 8 are difficult to interpret. However, lessons learned during the early 2000s are being taken into account in current deregulation activities, and it is expected that the business environment of the electric power industry will stabilize during the coming years.

3 Industry Outlook

This section discusses industry trends that are currently affecting the structure of the electric power industry. The most important change in the electric power industry continues to be industry deregulation – the transition from a highly regulated monopolistic industry to a less regulated, more competitive industry. Section 3.1 discusses the current status of deregulation. Section 3.2 presents a summary of forecasts from the Annual Energy Outlook 2005.

3.1 Current Status of Industry Deregulation

The electric power industry is evolving from a highly regulated, monopolistic industry with traditionally-structured electric utilities to a less regulated, more competitive industry.[8] The industry has traditionally

8 Several key pieces of Federal legislation have made the changes in the industry's structure possible. The ***Public Utility Regulatory Policies Act (PURPA)*** of 1978 opened up competition in the generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities." The ***Energy Policy Act (EPACT)*** of 1992 removed constraints on ownership of electric generation facilities, and encouraged increased competition in the wholesale electric power business (Beamon, 1998).

been regulated based on the premise that the supply of electricity is a natural monopoly, where a single supplier could provide electric services at a lower total cost than could be provided by several competing suppliers. Over the past 10 years the relationship between electricity consumers and suppliers has undergone substantial change. California, Massachusetts, and Rhode Island were the first states to implement deregulation of the wholesale generating sector, followed by at least 10 more states by the end of 2000. Competitive reforms have slowed – or even been reversed – in more recent years, however, as a result of California's electricity crises, Enron's bankruptcy, and the financial collapse of many merchant generating and trading companies (Joskow, 2003).

The outlook for future structural reforms is mixed. The states that have proceeded the farthest with restructuring (including the Northeast, Texas, and a few states in the Midwest) are committed to making the competitive wholesale and retail markets work. California is still recovering from its 2000/2001 electricity crisis, and its long-run electricity strategy is uncertain. Those states that have not yet begun restructuring activities (mainly in the South, Southeast, and West) appear to be in a wait-and-see mode and are unlikely to proceed with deregulation unless the benefits of doing so are demonstrated by those states at the forefront of restructuring (Joskow, 2003).

3.1.1 Key changes in the industry's structure

Industry deregulation has changed and continues to fundamentally affect the structure of the electric power industry. Some of the key changes in States that have implemented retail competition programs include:

- ***Provision of services:*** Under the traditional regulatory system, the generation, transmission, and distribution of electric power were handled by vertically-integrated utilities. Since the mid-1990s, competition has been introduced in the industry's generation sector in many states. Deregulation rules have resulted in a separation of power generation, transmission, and retail distribution services. Utilities that provide transmission and distribution services will continue to be regulated and will be required to divest of their generation assets or transfer them to unregulated affiliates. Entities that generate electricity will no longer be subject to geographic or rate regulation.

- ***Relationship between electricity providers and consumers:*** Under traditional regulation, utilities were granted a geographic franchise area and provided electric service to all customers in that area at a rate approved by the regulatory commission. A consumer's electric supply choice was limited to the utility franchised to serve their area. Similarly, electricity suppliers were not free to pursue customers outside their designated service territories. Although most consumers will continue to receive power through their local distribution company (LDC), retail competition will allow them to select the company that generates the electricity they purchase.

- ***Electricity prices:*** Under the traditional system, State and Federal authorities regulated all aspects of utilities' business operations, including their prices. Electricity prices were determined administratively for each utility, based on the average cost of producing and delivering power to customers and a reasonable rate of return. As a result of deregulation, competitive market forces will set generation prices. Buyers and sellers of power will negotiate through power pools or one-on-one to set the price of electricity. As in all competitive markets, prices will reflect the interaction of supply and demand for electricity. During most time periods, the price of electricity will be set by the generating unit with the highest operating costs needed to meet spot market generation demand (i.e., the "marginal cost" of production) (Beamon, 1998).

3.1.2 New industry participants

The Energy Policy Act of 1992 (EPACT) provides for open access to transmission systems, to allow nonutility generators to enter the wholesale market more easily. In response to these requirements, utilities have formed Independent System Operators (ISOs) to operate the transmission grid, Regional Transmission Organizations (RTOs) to promote efficiency in wholesale electricity markets, and open access same-time information systems (OASIS) to inform competitors of available capacity on their transmission systems. The advent of open transmission access has fostered the development of power marketers and ***power brokers*** as new participants in the electric power industry. Power marketers buy and sell wholesale electricity and fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC), since they take ownership of electricity and are engaged in interstate trade. Power marketers generally do not own generation or transmission facilities or sell power to retail customers. A growing number of power marketers have filed with the FERC and have had rates approved. Power brokers, on the other hand, arrange the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but do not take title to any of the power sold.

3.1.3 State activities

Many states have taken steps to promote competition in their electricity markets but the status of these efforts varies from state to state. As of February 2005, seventeen States had operating competitive retail electricity markets (WPSES, 2005). However, the difficult transition to a competitive electricity market in California, characterized by price spikes and rolling blackouts in 2000, has affected restructuring in that state and several others. Since the California energy crisis, five States (Arkansas, Montana, Nevada, New Mexico, and Oklahoma) have delayed the restructuring process pending further review of the issues while California has suspended direct retail access.

Even in States where consumer choice is available, important aspects of implementation may still be undecided. Key aspects of implementing restructuring include treatment of ***stranded costs***, pricing of transmission and distribution services, and the design of market structures required to ensure that the benefits of competition flow to all consumers (Beamon, 1998).

3.2 Energy Market Model Forecasts

This section discusses forecasts of electric energy supply, demand, and prices based on data and modeling by the Energy Information Administration (EIA) and presented in the *Annual Energy Outlook 2005* (U.S. DOE, 2005). The EIA models future market conditions through the year 2025, based on a range of assumptions regarding overall economic growth, global fuel prices, and legislation and regulations affecting energy markets. The projections are based on the results from the reference case of EIA's National Energy Modeling System (NEMS), using assumptions reflecting economic conditions as of October 2004.

3.2.1 Electricity demand

The AEO2005 projects electricity demand to grow by approximately 1.9% annually between 2003 and 2025. This growth is driven by an estimated 2.5% annual increase in the demand for electricity from the commercial sector associated with the continuing penetration of new telecommunications technologies, increased use of office equipment, and more rapid additions of floorspace. EIA expects electricity demand from the industrial sector to increase by 1.3% annually, largely in response to an increase in industrial output. Some of this additional industrial demand will be met by a 2.7% average annual increase in onsite generation. Residential demand is expected to increase by 1.6% annually over the same forecast period, due mostly to an increase in the average size of homes between 2003 and 2025. In addition, the amount of electricity used for air conditioning is expected to increase as a result of a population shift toward warmer climates, further contributing to the increase in energy consumption in the residential sector.

3.2.2 Capacity retirements

EIA predicts that 43 gigawatts of old, inefficient generating capacity will be retired between 2003 and 2025. Most retirements are expected to be oil and natural gas fired steam capacity. Inefficient oil and natural gas fired combustion turbines and coal fired capacity are also expected to come off-line. This capacity is expected to be replaced with newer natural gas combustion turbine or combined-cycle capacity. Most regions of the United States currently have excess capacity.

3.2.3 Capacity additions

Additional generating capacity will be needed to meet the estimated growth in electricity demand and offset the retirement of existing capacity. The need for new capacity is expected to be greatest in the Southeast and West, given the size of their electricity markets. Capacity additions in these two regions are expected to be more diverse than in other areas of the country. Of the new capacity forecasted to come on-line nationally between 2003 and 2025, more than 60% is projected to be combined-cycle technology or combustion turbine technology, including distributed generation capacity. This additional capacity is expected to be fueled by natural gas and to supply primarily peak and intermediate capacity. Approximately one third of the additional capacity forecasted to come on-line between 2003 and 2025 is expected to be provided by new coal-fired plants, while the remaining 7% is forecasted to come from renewable technologies.

3.2.4 Electricity generation

The AEO2005 projects increased electricity generation from both natural gas and coal-fired plants to meet growing demand and to offset lost capacity due to plant retirements. The forecast projects that coal-fired plants will remain the largest source of generation throughout the forecast period. Although coal-fired generation is predicted to increase steadily between 2003 and 2025, its share of total generation is expected to decrease slightly from 51% to an estimated 50%. This decrease in the share of coal generation is in favor of less capital-intensive and more efficient natural gas generation technologies. The share of total generation associated with gas-fired technologies is projected to increase from approximately 17% in 2003 to an estimated 24% in 2025, replacing nuclear power as the second largest source of electricity generation. Generation from renewable sources is projected to increase by 36% from 2003 to 2025; however, its share of total electricity supply is expected to decline from 9% in 2003 to 8% in 2025.

3.2.5 Electricity prices

EIA expects the average real price of electricity, as well as the price paid by customers in each sector (residential, commercial, and industrial), to decrease between 2003 and 2011 as a result of competition among electricity suppliers, excess generating capacity, and a decline in coal prices. However, by 2025, EIA predicts that the average real price of electricity will return to 2003 levels as a result of rising natural gas costs and electricity demand growth.

Glossary

Definitions are adapted from the following sources:

U.S. Department of Energy's *Electric Power Industry Overview*. At: http://www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html

U.S. Department of Energy's *International Energy Annual 2002 - Glossary*. At: http://www.eia.doe.gov/emeu/iea/glossary.html#W

U.S. Department of Energy's *Electric Power Annual Volume I - Glossary of Electricity Terms*. At: http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html

Base Load: A baseload generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Baseload units are generally the newest, largest, and most efficient of the three types of units (i.e., base load, intermediate load, and peak load units).

Combined-Cycle Unit: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Distribution: The delivery of electricity to retail customers (including homes, businesses, etc.).

Electricity Available to Consumers: Power available for sale to customers. Approximately 8% to 9% of net generation is lost during the transmission and distribution process.

Energy Policy Act (EPACT): In 1992 the EPACT removed constraints on ownership of electric generation facilities and encouraged increased competition in the wholesale electric power business.

Gas Turbine: A gas turbine typically consisting of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine. The hot gases expand to drive the generator and are then used to run the compressor.

Generation: The process of producing electric energy by transforming other forms of energy. Generation is also the amount of electric energy produced, expressed in ***watthours (Wh)***.

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Hydroelectric Generating Unit: A unit in which the turbine generator is driven by falling water or natural river current.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than base load but less than peak load. Intermediate-load units are used during the transition between base load and peak load requirements.

Internal Combustion Engine: An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal fuel types used in these generators.

Kilowatthour (kWh): One thousand ***watthours (Wh)***.

Megawatt (MW): One million ***watts***.

Nameplate Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer. Nameplate capacity is expressed in ***watts*** or ***megawatts (MW)***.

Net Generation: Gross generation minus plant use from all plants owned by the same utility.

Nonutility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

Other Prime Mover: Methods of power generation other than ***steam turbine***, ***combined-cycle unit***, ***gas combustion turbine***, ***internal combustion engine***, and ***hydroelectric generating unit***. Other prime movers include: geothermal, solar, wind, and biomass.

Peak load: A peakload generating unit, normally the least efficient of the three unit types (i.e., base load, intermediate load, and peak load units), is used to meet requirements during the periods of greatest, or peak, load on the system.

Power Marketer: Business entity engaged in buying, selling, and marketing electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission for status as a power marketer.

Power Broker: An entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold.

Prime Mover: The engine, turbine, water wheel, or similar machine that drives an electric generator. Also, for reporting purposes, a device that directly converts energy to electricity, e.g., photovoltaic, solar, and fuel cell(s).

Public Utility Regulatory Policies Act (PURPA): In 1978 PURPA opened up competition in the electricity generation market by creating a class of nonutility electricity-generating companies referred to as “qualifying facilities.”

Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities.

Steam Turbine: A generating unit in which the prime mover is a steam turbine. The turbines convert thermal energy (steam or hot water) produced by generators or boilers to mechanical energy or shaft torque. This mechanical energy is used to power electric generators, including combined-cycle electric generating units, that convert the mechanical energy to electricity.

Stranded Cost: Prudent costs incurred by a utility that may not be recoverable under market based retail competition. Examples are undepreciated generating facilities, deferred costs, and long-term contract costs.

Transmission: The movement or transfer of 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.

Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities.

Watt: The electrical unit of power. The rate of energy transfer equivalent to one ampere flowing under the pressure of one volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

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