Chapter A3: Profile of the Electric Power Industry

CHAPTER CONTENTS

INTRODUCTION

This profile compiles and analyzes economic and financial 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 from the Proposed Section 316(b) Phase II Existing Facilities Rule.

The electric power industry is one of the most extensively studied industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis. This profile is not intended to duplicate those efforts. Rather, this profile compiles, summarizes, and presents those industry data that are important in the context of the proposed Phase II rule. For more information on general concepts, trends, and developments in the electric power industry, the last section of this profile, "References," presents a select list of other publications on the industry.

The remainder of this profile is organized as follows:

- Section A3-1 provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.
- Section A3-2 provides data on industry production and capacity.
- Section A3-3 focuses on the in-scope section 316(b) facilities. This section provides information on the geographical, physical, and financial characteristics of the in-scope phase II facilities.
- Section A3-4 provides a brief discussion of factors affecting the future of the electric power industry, including the status of restructuring, and summarizes forecasts of market conditions through the year 2020.

A3-1 INDUSTRY OVERVIEW

This section provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.

A3-1.1 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):[1]

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[2] Electric energy is produced using a specific generating technology, e.g., internal combustion engines and turbines. Turbines can be driven by wind, moving water (hydroelectric), or steam from fossil fuel-fired boilers or nuclear reactions. Other methods of power generation include geothermal 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 (AC) 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 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 uses cooling water and is subject to section 316(b). The remainder of this profile will focus on the generation sector of the industry.

A3-1.2 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, petroleum, and natural gas) as an energy source and employ some type of turbine to produce electricity. The six most common prime movers are (U.S. DOE, 2000a):

- ***Steam Turbine:*** Steam turbine, or "steam electric" units require a fuel source to boil water and produce steam that drives the turbine. Either the burning of fossil fuels or a nuclear reaction can be used to produce the heat and steam necessary to generate electricity. These units are generally ***baseload*** units that are run continuously to serve the minimum load required by the system. Steam electric units generate the majority of electricity produced at power plants in the U.S.

- ***Gas Combustion Turbine:*** Gas turbine units burn a combination of natural gas and distillate oil in a high pressure chamber to produce hot gases that are passed directly through the turbine. Units with this prime mover are generally less than 100 megawatts in size, less efficient than steam turbines, and used for ***peakload*** operation serving the highest daily, weekly, or seasonal loads. Gas turbine units have quick startup times and can be installed at a variety of site locations, making them ideal for peak, emergency, and reserve-power requirements.

- ***Combined-Cycle Turbine:*** Combined-cycle units utilize both steam and gas turbine prime mover technologies to increase the efficiency of the gas turbine system. After combusting natural gas in gas turbine units, the hot gases from the turbines are transported to a waste-heat recovery steam boiler where water is heated to produce steam for a second steam turbine. The steam may be produced solely by recovery of gas turbine exhaust or with additional fuel input to the steam boiler. Combined-cycle generating units are generally used for ***intermediate loads***.

[1] Terms highlighted in bold and italic font are defined in the glossary at the end of this chapter.

[2] The terms "plant" and "facility" are used interchangeably throughout this profile.

- ***Internal Combustion Engines:*** Internal combustion engines contain one or more cylinders in which fuel is combusted to drive a generator. These units are generally about 5 megawatts in size, can be installed on short notice, and can begin producing electricity almost instantaneously. Like gas turbines, internal combustion units are generally used only for peak loads.

- ***Water Turbine:*** Units with water turbines, or "hydroelectric units," use either falling water or the force of a natural river current to spin turbines and produce electricity. These units are used for all types of loads.

- ***Other Prime Movers:*** Other methods of power generation include geothermal, solar, wind, and biomass prime movers. The contribution of these prime movers is small relative to total power production in the U.S., but the role of these prime movers may expand in the future because recent legislation includes incentives for their use.

Table A3-1 provides data on the number of existing utility and nonutility power plants by prime mover. This table includes all plants that have at least one non-retired unit and that submitted Forms EIA-860A (Annual Electric Generator Report - Utilities) or EIA-860B (Annual Electric Generator Report - Nonutilities) in 1999.[3] 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 electricity generation.

Table A3-1: Number of Existing Utility and Nonutility Plants by Prime Mover, 1999

Prime Mover	Utility[a]	Nonutility[a]
	Number of Plants	Number of Plants
Steam Turbine	803	821
Combined-Cycle	59	201
Gas Turbine	335	372
Internal Combustion	642	245
Hydroelectric	1,237	476
Other	49	90
Total	**3,125**	**2,205**

[a] See definition of utility and nonutility in Section A3-1.3.

Source: U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

Only prime movers with a steam electric generating cycle use substantial amounts of cooling water. These generators include steam turbines and combined-cycle technologies. As a result, the analysis in support of the proposed Phase II rule focuses on generating plants with a steam electric prime mover. This profile will, therefore, differentiate between steam electric and other prime movers.

A3-1.3 Ownership

The U.S. electric power industry consists of two broad categories of firms that own and operate electric generating plants: utilities and nonutilities. Generally, they can be defined as follows (U.S. DOE, 2000a):

- ***Utility:*** A regulated entity providing electric power, traditionally vertically integrated. Utilities 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.

[3] At the time of publication of this document, 1999 was the most recent year for which complete EIA data were available for existing utility and nonutility plants. As of March 2002 EIA 860B data were not available for year 2000. As such, this profile is based on 1999 data.

- ***Nonutility:*** Entities that generate power for their own use and/or for sale to utilities and others. Nonutility power producers include cogenerators, small power producers, and independent power producers. Nonutilities do not have a designated franchised service area and do not transmit or distribute electricity.

Utilities can be further divided into three major ownership categories: investor-owned utilities, publicly-owned utilities, and rural electric cooperatives. Each category is discussed below.

a. Investor-owned utilities

Investor-owned utilities (IOUs) are for-profit businesses that can take two basic organizational forms: the individual corporation and the holding company. An individual corporation is a single utility company with its own investors; a holding company is a business entity that owns one or more utility companies and may have other diversified holdings as well. Like all businesses, the objective of an IOU is to produce a return for its investors. IOUs are entities with designated franchise areas. They are required to charge reasonable and comparable prices to similar classifications of consumers and give consumers access to services under similar conditions. Most IOUs engage in all three activities: generation, transmission, and distribution. In 1999, IOUs operated 1,662 facilities, which accounted for approximately 58 percent of all U.S. electric generation capacity (U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE, 1998c).

b. Publicly-owned utilities

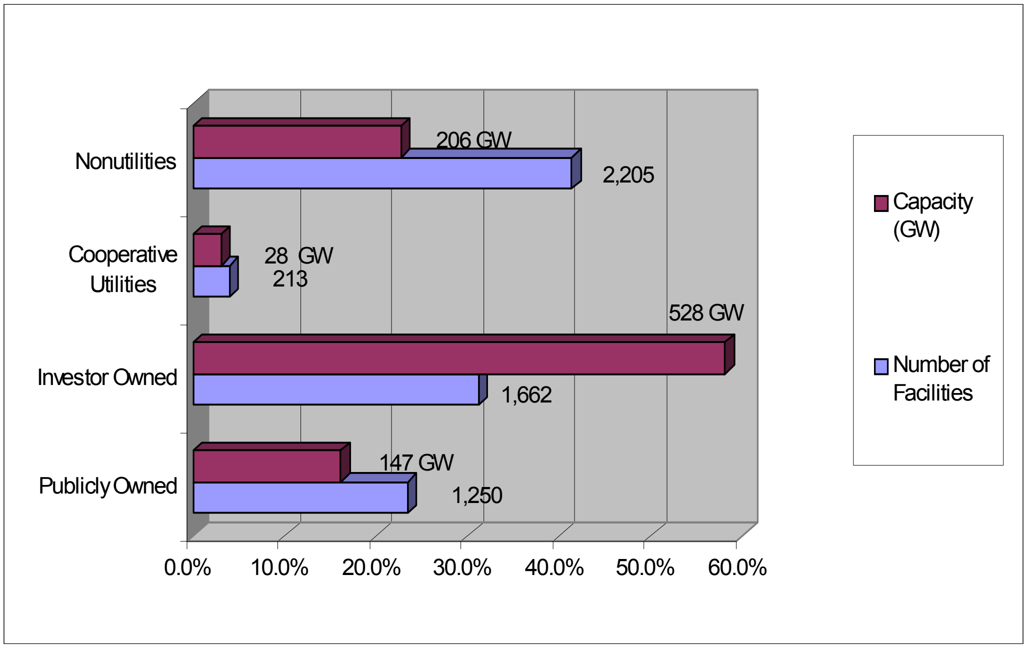
Publicly-owned electric utilities can be municipalities, public power districts, state authorities, irrigation projects, and other state agencies established to serve their local municipalities or nearby communities. Excess funds or "profits" from the operation of these utilities are put toward community programs and local government budgets, increasing facility efficiency and capacity, and reducing rates. This profile also includes federally-owned facilities in this category. Most municipal utilities are nongenerators engaging solely in the purchase of wholesale electricity for resale and distribution. The larger municipal utilities, as well as state and federal utilities, usually generate, transmit, and distribute electricity. 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 1999, publicly-owned utilities operated 1,250 facilities and accounted for approximately 16 percent of all U.S. electric generation capacity (U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE, 1998c).

c. Rural electric cooperatives

Cooperative electric utilities ("coops") are member-owned entities created to provide electricity to those members. These utilities, established under the Rural Electrification Act of 1936, provide electricity to small rural and farming communities (usually fewer than 1,500 consumers). 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 34 states and are incorporated under state laws. In 1999, rural electric cooperatives operated 213 generating facilities, and accounted for approximately 3 percent of all U.S. electric generation capacity. (U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE, 1998c).

Figure A3-1 presents the number of generating facilities and their capacity in 1999, by type of ownership.[4] 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 Forms EIA-860A or EIA-860B in 1999. The graphic shows that nonutilities account for the largest percentage of facilities (2,205, or about 41 percent), but only represent 23 percent of total U.S. generating capacity. Investor-owned utilities operate the second largest number of facilities, 1,662, and generate 58 percent of total U.S. capacity.

Figure A3-1: Distribution of Facilities and Capacity by Ownership Type, 1999 [a]



[a] In order to best understand the landscape of the electric power generating market EPA tracked ownership changes from utilities to nonutilities, and vice versa, through January, 2002. These changes have been incorporated into the analysis where possible.

Source: *U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c; U.S. DOE 1998c.*

Plants owned and operated by utilities and nonutilities may be affected differently by the proposed Phase II rule due to differing competitive roles in the market. Much of the following discussion therefore differentiates between these two groups.

A3-2 Domestic Production

This section presents an overview of U.S. generating capacity and electricity generation. Subsection A3-2.1 provides data on capacity, and Subsection A3-2.2 provides data on generation. Subsection A3-2.3 presents an overview of the geographic distribution of generation plants and capacity.

[4] EPA tracked ownership changes from utilities to nonutilities, and vice versa, through January 2002. These changes are incorporated into the profile. As such, the universe of facilities (and their corresponding characteristics) is based on EIA 1999 data, adjusted to reflect EPA's most current knowledge.

A3-2.1 Generating Capacity[5]

Utilities own and operate the majority of the generating capacity in the United States (77 percent). Nonutilities owned only 23 percent of the total capacity in 1999 and produced roughly 21 percent of the electricity in the country. Nonutility capacity and generation have increased substantially in the past few years, however, since passage of legislation aimed at increasing competition in the industry. Nonutility capacity has increased by 247 percent between 1991 and 1998, compared with the decrease in utility capacity of eight percent over the same time period.[6]

Figure A3-2 shows the growth in utility and nonutility capacity from 1991 to 1999. The growth in nonutility capacity, combined with a slight decrease in utility capacity, has resulted in a modest growth in total generating capacity. The significant increase in nonutility capacity, and decrease in utility capacity in 1999 is attributable to utilities being sold to nonutilities.

Capacity/Capability

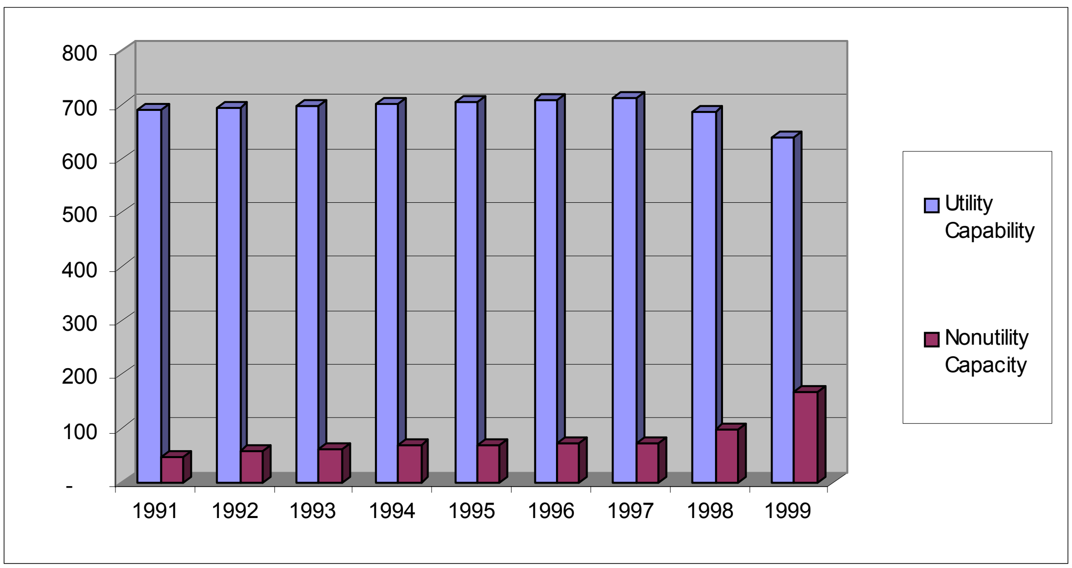
The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures:

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

Net capability is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The nameplate capacity of a generating unit is generally greater than its net capability.

U.S. DOE, 2000a

Figure A3-2: Generating Capability & Capacity, 1991 to 1999[a]



Source: U.S. DOE, 2000c; U.S. DOE,1996b.

[5] The numbers presented in this section are *capability* for utilities and *capacity* for nonutilities (see text box for the difference between these two measures). For convenience purposes, this section will refer to both measures as"capacity."

[6] More accurate data were available starting in 1991, therefore, 1991 was selected as the initial year for trends analysis.

A3-2.2 Electricity Generation

Total net electricity generation in the U.S. for 1999 was 3,723 billion kWh. Utility-owned plants accounted for 85 percent of this amount. Total net generation has increased by 21 percent over the nine-year period from 1991 to 1999. During this period, nonutilities increased their electricity generation by 131 percent. In comparison, generation by utilities increased by only 12 percent (U.S. DOE, 2000b; U.S. DOE, 2000c; U.S. DOE, 1995a; U.S. DOE, 1995b). This trend is expected to continue with deregulation in the coming years, as more facilities are purchased and built by nonutility power producers.

Table A3-2 shows the change in net generation between 1991 and 1999 by fuel source for utilities and nonutilities.

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 percent of net generation is lost during the transmission and distribution process.

U.S. DOE, 2000a

Table A3-2: Net Generation by Energy Source and Ownership Type, 1991 to 1999 (GWh)

Energy Source	Utilities			Nonutilities[a]			Total		
	1991	1999	% Change	1991	1999	% Change	1991	1999	% Change
Coal	1,551	1,768	14%	39	126	219%	1,591	1,893	19%
Hydropower	280	294	5%	6	22	248%	286	315	10%
Nuclear	613	725	18%	0	9	0%	613	734	20%
Petroleum	111	87	-22%	8	21	181%	119	108	-9%
Gas	264	296	12%	127	296	132%	392	592	51%
Renewables[b]	10	4	-63%	57	76	33%	67	80	19%
Total	**2,830**	**3,174**	**12%**	**238**	**549**	**131%**	**3,067**	**3,723**	**21%**

[a] Nonutility generation was converted from gross to net generation based on prime mover-specific conversion factors (U.S. DOE, 2000c). As a result of this conversion, the total net generation estimates differ slightly from EIA published totals by fuel type.

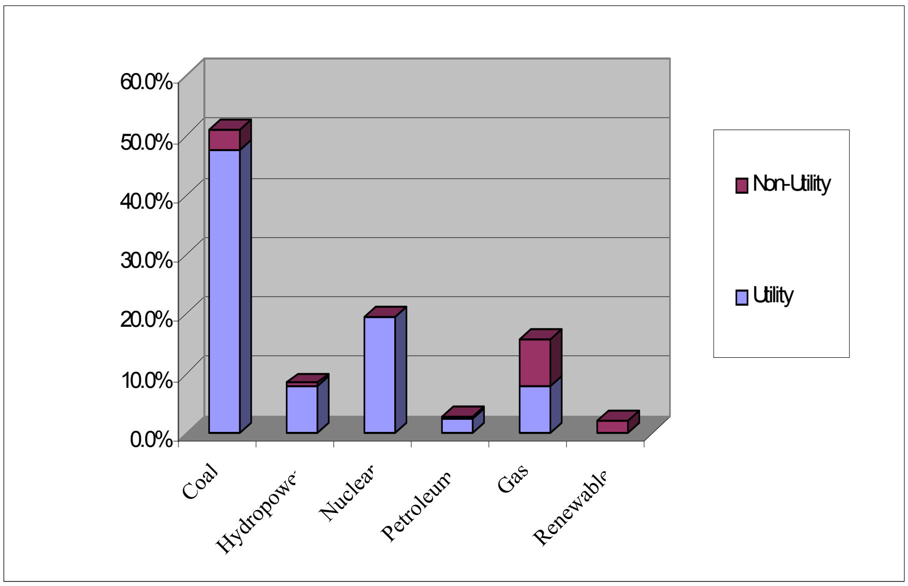
[b] Renewables include solar, wind, wood, biomass, and geothermal energy sources.

Source: U.S. DOE, 2000b;U.S. DOE, 2000c; U.S. DOE, 1995a; U.S. DOE,1995b.

As shown in Table A3-2, nuclear generation grew the fastest among the utility fuel source categories, increasing by 18 percent between 1991 and 1999. Coal generation increased by 14 percent, while gas generation increased by 12 percent. Utility generation from renewable energy sources decreased significantly (63 percent) between 1991 and 1999. A majority of this decline (48 percent) occurred from 1998 to 1999. Nonutility generation has grown at a much higher rate between 1991 and 1999 with the passage of legislation aimed at increasing competition in the industry. Nonutility hydroelectric generation grew the fastest among the energy source categories, increasing 248 percent between 1991 and 1999. Generation from coal-fired facilities also increased substantially, with a 219 percent increase in generation between 1991 and 1999.

Figure A3-3 shows total net generation for the U.S. by primary fuel source for utilities and nonutilities. Electricity generation from coal-fired plants accounts for 47 percent of total 1999 generation. Electric utilities generate 93 percent (1,768 billion kWh) of the 1,893 billion kWh of electricity generated by coal-fired plants. This represents approximately 56 percent of total utility generation. The remaining 7 percent (126 billion kWh) of coal-fired generation is provided by nonutilities, accounting for 23 percent of total nonutility generation. The second largest source of electricity generation is nuclear power plants, accounting for 20 percent of both total generation and total utility generation. Figure A3-3 shows that virtually 99.8 percent of nuclear generation is owned and operated by utilities. Another significant source of electricity generation is gas-fired power plants, which account for 54 percent of nonutility generation and 16 percent of total generation.

Figure A3-3: Percent of Electricity Generation by Primary Fuel Source, 1999



Source: U.S. DOE,2000b; U.S. DOE,2000c.

The proposed Phase II rule will affect facilities differently based on the fuel sources and prime movers used to generate electricity. As mentioned in Section A3-1.2 above, only prime movers with a steam electric generating cycle use substantial amounts of cooling water.

A3-2.3 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, while the other two have limited interconnection to each other. The Eastern and Western systems are integrated or have links to the Canadian grid system. The Western and Texas systems have links with Mexico.

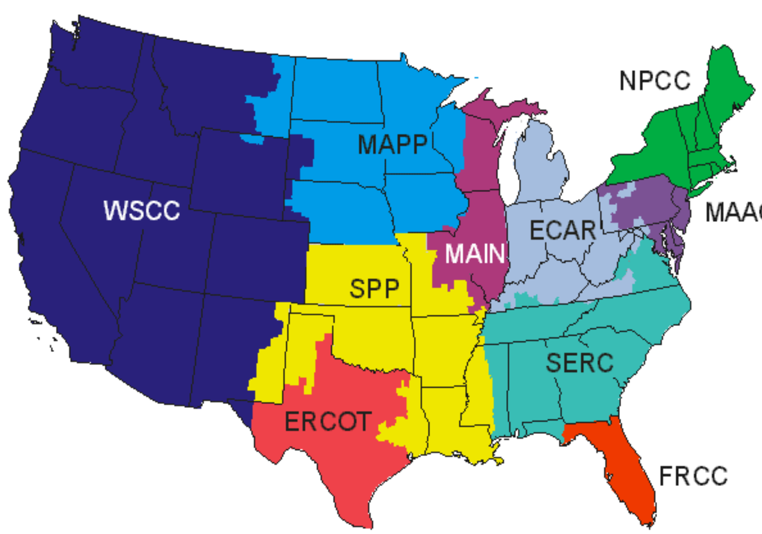
These major networks contain extra-high voltage connections that allow for power transactions from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system reliability. ***Reliability*** refers to 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 nine regional councils that cover the 48 contiguous states, 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 in the previous section, NERC regions do not necessarily follow any state boundaries. Figure A3-4 below provides a map of the NERC regions, which include:

- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas
- FRCC – Florida Reliability Coordinating Council
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnect Network
- MAPP – Mid-Continent Area Power Pool (U.S.)
- NPCC – Northeast Power Coordinating Council (U.S.)
- SERC – Southeastern Electric Reliability Council
- SPP – Southwest Power Pool
- WSCC – Western Systems Coordinating Council (U.S.)

Alaska and Hawaii are not shown in Figure A3-4. 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 (HI).

Figure A3-4: North American Electric Reliability Council (NERC) Regions



Source: EIA, 1996.

The proposed Phase II rule may affect plants located in different NERC regions differently. Economic characteristics of existing facilities affected by the proposed Phase II rule are likely to vary across regions by fuel mix, and the costs of fuel, transportation, labor, and construction. Baseline differences in economic characteristics across regions may influence the impact of the proposed Phase II rule on profitability, electricity prices, and other impact measures. However, as discussed in *Chapter B3: Electricity Market Model Analysis*, the proposed Phase II rule will have little or no impact on electricity prices in each region since the proposed Phase II rule is relatively inexpensive relative to the overall production costs in any region.

Table A3-3 shows the distribution of all existing utilities, utility-owned plants, and capacity by NERC region. The table shows that while the Mid-Continent Area Power Pool (MAPP) has the largest number of utilities, 24 percent, these utilities only represent five percent of total capacity. Conversely, only five percent of the nation's utilities are located in the Southeastern Electric Reliability Council (SERC), yet these utilities are generally larger and account for 23 percent of the industry's total generating capacity.

Table A3-3: Distribution of Existing Generation Utilities, Utility Plants, and Capacity by NERC Region, 1999

NERC Region	Generation Utilities		Utility Plants		Capacity	
	Number	% of Total	Number	% of Total	Total MW	% of Total
ASCC	52	6%	168	5%	2,019	0%
ECAR	100	11%	301	10%	112,439	16%
ERCOT	28	3%	107	3%	55,908	8%
FRCC	18	2%	62	2%	38,155	5%
HI	3	0%	16	1%	1,592	0%
MAAC	21	2%	93	3%	23,649	3%
MAIN	65	7%	207	7%	45,120	6%
MAPP	212	24%	406	13%	36,094	5%
NPCC	73	8%	394	13%	45,948	7%
SERC	43	5%	333	11%	164,235	23%
SPP	144	16%	262	8%	45,782	7%
WSCC	129	14%	773	25%	131,644	19%
Unknown	3	0%	3	0%	39	0%
Total	**891**	**100%**	**3,125**	**100%**	**702,624**	**100%**

Source: U.S. DOE, 1999a; U.S. DOE, 1999c.

Table A3-4 shows the distribution of existing nonutility plants and capacity by NERC region. The table shows that the Western Systems Coordinating Council (WSCC) has the largest number of nonutility plants, with 613. MAAC, which contains only 7 percent of the total number of nonutility plants, accounts for the largest portion of capacity, with 43,547 MW (21 percent).

Table A3-4: Distribution of Nonutility Plants and Capacity by NERC Region, 1999

NERC Region	Nonutility Plants		Capacity	
	Number	% of Total	Total MW	% of Total
ASCC	26	1%	300	0%
ECAR	139	6%	8,883	4%
ERCOT	75	3%	9,525	5%
FRCC	57	3%	4,173	2%
HI	11	0%	740	0%
MAAC	155	7%	43,547	21%
MAIN	136	6%	30,398	15%
MAPP	70	3%	1,599	1%
NPCC	531	24%	39,720	19%
SERC	279	13%	16,293	8%
SPP	43	2%	1,844	1%
WSCC	613	28%	39,894	19%
Unknown	70	3%	9,584	5%
Total	**2,205**	**100%**	**206,500**	**100%**

Source: U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

A3-3 Existing Plants with CWIS and NPDES Permit

Section 316(b) of the Clean Water Act applies to a point source facility uses or proposes to use a cooling water intake structure water that directly withdraws cooling water from a water of the United States. Among power plants, only those facilities employing a steam electric generating technology require cooling water and are therefore of interest to this analysis. Steam electric generating technologies include units with steam electric turbines and combined-cycle units with a steam component.

The following sections describe existing utility and nonutility power plants that would be subject to the proposed Phase II rule. The Proposed Section 316(b) Phase II Existing Facilities Rule applies to existing steam electric power generating facilities that meet all of the following conditions:

- They meet the definition of an existing steam electric power generating facility as specified in § 125.93 of this rule;
- They use a cooling water intake structure or structures, or obtain cooling water by any sort of contract or arrangement with an independent supplier who has a cooling water intake structure;
- Their cooling water intake structure(s) withdraw(s) cooling water from waters of the U.S., and at least twenty-five (25) percent of the water withdrawn is used for contact or non-contact cooling purposes;
- They have an NPDES permit or are required to obtain one; and
- They have a design intake flow of 50 MGD or greater.

The proposed Phase II rule also covers substantial additions or modifications to operations undertaken at such facilities. While all facilities that meet these criteria are subject to the regulation, this Economic and Benefit Analysis (EBA) focuses on 539 utility and non-utility steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey as being "in-scope" of this proposed rule. These 539 facilities represent 550 facilities nation-wide.[7] The remainder of this chapter will refer to these facilities as "existing section 316(b) plants."

Utilities and nonutilities are discussed in separate subsections because the data sources, definitions, and potential factors influencing the magnitude of impacts are different for the two sectors. Each subsection presents the following information:

- ***Ownership type:*** This section discusses existing section 316(b) facilities with respect to the entity that owns them. Utilities are classified into investor-owned utilities, rural electric cooperatives, municipalities, and other publicly-owned utilities (see Section A3-1.3). This differentiation is important because EPA has separately considered impacts on governments in its regulatory development (see *Chapter B9: UMRA Analysis* for the analysis of government impacts of the proposed Phase II rule). The utility ownership categories do not apply to nonutilities. The ownership type discussion for nonutilities differentiates between two types of plants: (1) plants that were originally built by nonutility power producers ("original nonutility plants") and (2) plants that used to be owned by utilities but that were sold to nonutilities as a result of industry deregulation ("former utility plants"). Differentiation between these two types of nonutilities is important because of their different economic and operational characteristics.

- ***Ownership size:*** This section presents information on the Small Business Administration (SBA) entity size of the owners of existing section 316(b) facilities. EPA has considered economic impacts on small entities when developing this regulation (see *Chapter B4: Regulatory Flexibility Analysis* for the small entity analysis of new facilities subject to the proposed Phase II rule).

- ***Plant size:*** This section discusses the existing section 316(b) facilities by the size of their generation capacity. The size of a plant is important because it partly determines its need for cooling water.

- ***Geographic distribution:*** This section discusses plants by NERC region. The geographic distribution of facilities is important because a high concentration of facilities with costs under a regulation could lead to impacts on a regional level. Everything else being equal, the higher the share of plants with costs, the higher the likelihood that there may be economic and/or system reliability impacts as a result of the regulation.

- ***Water body and cooling system type:*** This section presents information on the type of water body from which existing section 316(b) facilities draw their cooling water and the type of cooling system they operate. Cooling systems can be either once-through or recirculating systems.[8] Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

WATER USE BY STEAM ELECTRIC POWER PLANTS

Steam electric generating plants are the single largest industrial users of water in the United States. In 1995:

- steam electric plants withdrew an estimated 190 billion gallons per day, accounting for 39 percent of freshwater use and 47 percent of combined fresh and saline water withdrawals for offstream uses (uses that temporarily or permanently remove water from its source);
- fossil-fuel steam plants accounted for 71 percent of the total water use by the power industry;
- nuclear steam plants and geothermal plants accounted for 29 percent and less than 1 percent, respectively;
- surface water was the source for more than 99 percent of total power industry withdrawals;
- approximately 69 percent of water intake by the power industry was from freshwater sources, 31 percent was from saline sources.

USGS, 1995

[7] EPA applied sample weights to the 539 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA 2000).

[8] Once-through cooling systems withdraw water from the water body, run the water through condensers, and discharge the water after a single use. Recirculating systems, on the other hand, reuse water withdrawn from the source. These systems take new water into the system only to replenish losses from evaporation or other processes during the cooling process. Recirculating systems use cooling towers or ponds to cool water before passing it through condensers again.

A3-3.1 Existing Section 316(b) Utility Plants

EPA identified steam electric prime movers that require cooling water using information from the EIA data collection U.S. DOE, 1999a.[9] These prime movers include:

- Atmospheric Fluidized Bed Combustion (AB)
- Combined-Cycle Steam Turbine with Supplementary Firing (CA)
- Combined Cycle - Total Unit (CC)
- Steam Turbine – Common Header (CH)
- Combined-Cycle – Single Shaft (CS)
- Combined-Cycle Steam Turbine – Waste Heat Boiler Only (CW)
- Steam Turbine – Geothermal (GE)
- Integrated Coal Gasification Combined-Cycle (IG)
- Steam Turbine – Boiling Water Nuclear Reactor (NB)
- Steam Turbine – Graphite Nuclear Reactor (NG)
- Steam Turbine – High Temperature Gas-Cooled Nuclear Reactor (NH)
- Steam Turbine – Pressurized Water Nuclear Reactor (NP)
- Steam Turbine – Solar (SS)
- Steam Turbine – Boiler (ST)

Using this list of steam electric prime movers, and U.S. DOE, 1999a information on the reported operating status of units, EPA identified 862 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Surveys was used to determine that 416 of the 862 facilities operate a CWIS and hold an NPDES permit. Table A3-5 provides information on the number of utilities, utility plants, and generating units, and the generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the part of the industry potentially affected by the proposed Phase II rule.

Table A3-5: Number of Existing Utilities, Utility Plants, Units, and Capacity, 1999

	Total[a]	Steam Electric[b]		Steam Electric with CWIS and NPDES Permit[c]	
		Number	% of Total	Number	% of Total
Utilities	891	315	35%	148	17%
Plants	3,125	862	28%	416	13%
Units	10,460	2,226	21%	1,220	12%
Nameplate Capacity (MW)	702,624	533,503	76%	344,849	49%

[a] Includes only generating capacity not permanently shut down or sold to nonutilities.
[b] Utilities and plants are listed as steam electric if they have at least one steam electric unit.
[c] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

Table A3-5 shows that the while the 862 steam electric plants account for only 28 percent of all plants, these plants account for 76 percent of all capacity. The 416 in-scope plants represent 13 percent of all plants, are owned by 17 percent of all utilities, and account for approximately 49 percent of reported utility generation capacity. The remainder of this section will focus on the 416 utility plants.

[9] U.S. DOE, 1999a (Annual Electric Generator Report) collects data used to create an annual inventory of utilities. The data collected includes: type of prime mover; nameplate rating; energy source; year of initial commercial operation; operating status; cooling water source, and NERC region.

a. Ownership type

Table A3-6 shows the distribution of the 148 utilities that own the 416 existing section 316(b) plants, as well as the total generating capacity of these entities, by type of ownership. The table also shows the total number of plants, utilities, and capacity by type of ownership. Utilities can be divided into three major ownership categories: investor-owned utilities, publicly-owned utilities (including municipalities, political subdivision, and federal and state-owned utilities), and rural electric cooperatives. Table A3-6 shows that approximately 19 percent of plants operated by investor-owned utilities have a CWIS and an NPDES permit. These 313 facilities account for 75 percent of all existing plants with a CWIS and an NPDES permit (313 divided by 416). The percentage of all plants that have a CWIS and an NPDES permit is lower for the other ownership types: 12 percent for rural electric cooperatives, six percent for municipalities, and seven percent for other publicly owned utilities.

Table A3-6: Existing Utilities, Plants, and Capacity by Ownership Type, 1999[a]

Ownership Type	Utilities			Plants			Capacity (MW)		
	Total Number of Utilities	Utilities with Plants with CWIS and NPDES		Total Number of Plants	Plants with CWIS and NPDES[b]		Total Capacity	Capacity with CWIS and NPDES[b]	
		Number	% of Total		Number	% of Total		MW	% of Total
Investor-Owned	177	88	50%	1,662	313	19%	527,948	287,774	55%
Coop	71	14	20%	213	25	12%	28,151	8,582	30%
Municipal	578	38	7%	867	50	6%	42,904	15,870	37%
Other Public	65	8	12%	383	27	7%	103,621	32,623	31%
Total	**891**	**148**	**17%**	**3,125**	**416**	**13%**	**702,624**	**344,850**	**68%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

b. Ownership size

EPA used the Small Business Administration (SBA) small entity size standards for SIC code 4911 (electric output of four million megawatt hours or less per year) to make the small entity determination.[10] Table A3-7 provides information on the total number of utilities and utility plants owned by small entities by type of ownership. The table shows that 26 of the 148 utilities with existing section 316(b) plants, or 18 percent, may be small. The size distribution varies considerably by ownership type: only 13 percent of all other public utilities and zero percent of all investor-owned utilities with existing section 316(b) plants may be small, compared to 43 percent of all coop and 50 percent of all municipalities. The same is true on the plant level: none of the 313 existing section 316(b) plants operated by an investor-owned utility, and four percent of the other publicly owned utilities are owned by a small entity. The corresponding percentages for municipalities and electric cooperatives are 38 percent and 24 percent, respectively.[11]

Table A3-7 also shows the percentage of all small utilities and all plants owned by small utilities that comprise the "section 316(b)" part of the industry. Twenty-six, or four percent, of all 697 small utilities operate existing section 316(b) plants. At the plant level, between one percent (other public) and four percent (Coop) of small utility plants have CWIS and NPDES permits.

Table A3-7: Existing Small Utilities and Utility Plants by Ownership Type, 1999

Ownership Type	Total				With CWIS and NPDES Permit [a,b]				Small with CWIS and NPDES/ Total Small
	Total	Small	Unknown	% Small	Total	Small	Unknown	% Small	
Utilities									
Investor-Owned	177	47	11	27%	88	0	0	0%	0%
Coop	71	54	1	76%	14	6	0	43%	11%
Municipal	578	557	11	96%	38	19	2	50%	3%
Other Public	65	39	9	60%	8	1	0	13%	3%
Total	**891**	**697**	**32**	**78%**	**148**	**26**	**2**	**18%**	**4%**
Plants									
Investor-Owned	1,662	211	26	13%	313	0	0	0%	0%
Coop	213	154	0	72%	25	6	0	24%	4%
Municipal	867	781	9	90%	50	19	2	38%	2%
Other Public	383	136	71	36%	27	1	0	4%	1%
Total	**3,125**	**1,282**	**106**	**41%**	**416**	**26**	**2**	**11%**	**2%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. SBA, 2000; U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE 1999d.

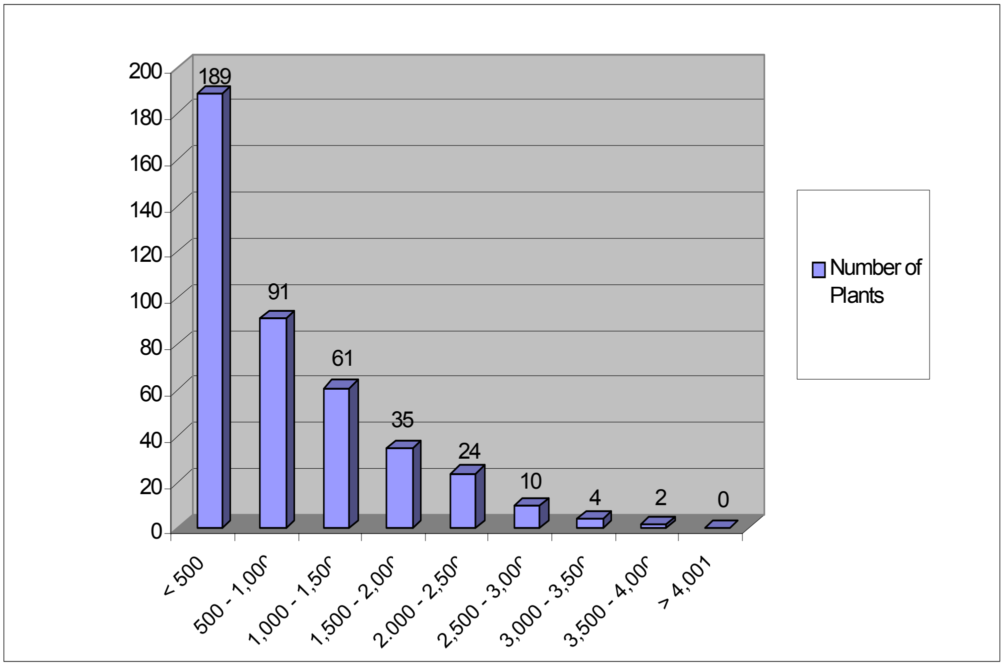
[10] SBA defines "small business" as a firm with an annual electricity output of four million MWh or less and "small governmental jurisdictions" as governments of cities, counties, towns, school districts, or special districts with a population of less than 50,000 people. Information on the population of all municipal utilities was not readily available for all municipalities. EPA therefore used the small business standard for all utilities.

[11] Note that for investor-owned utilities, the small business determination is generally made at the holding company level. Holding company information was not available for all investor-owned utilities. The small business determination was therefore made at the utility level. This approach will overstate the number of investor-owned utilities and their plants that are classified as small.

c. Plant size

EPA also analyzed the steam electric facilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure A3-5 presents the distribution of existing utility plants with a CWIS and an NPDES permit by plant size. Of the 416 plants, 189 (45 percent) have a total nameplate capacity of 500 megawatts or less, and 280 (67 percent) have a total capacity of 1,000 megawatts or less.

Figure A3-5: Number of Existing Phase II Facilities by Plant Size (in MW), 1999 [a,b]



[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

d. Geographic distribution

Table A3-8 shows the distribution of existing section 316(b) utility plants by NERC region. The table shows that there are considerable differences between the regions in terms of both the number of existing utility plants with a CWIS and an NPDES permit, and the percentage of all plants that they represent. Excluding Alaska, which only has one utility plant with a CWIS and an NPDES permit, the percentage of existing section 316(b) facilities ranges from two percent in the Western Systems Coordinating Council (WSCC) to 49 percent in the Electric Reliability Council of Texas (ERCOT). The Southeastern Electric Reliability Council (SERC) has the highest absolute number of existing section 316(b) facilities with 94, or 23 percent of all facilities, followed by the East Central Area Reliability Coordination Agreement (ECAR) with 90 facilities, or 22 percent of all facilities.

Table A3-8: Existing Utility Plants by NERC Region, 1999

NERC Region	Total Number of Plants	Plants with CWIS and NPDES Permit[a,b]	
		Number	% of Total
ASCC	168	1	1%
ECAR	301	90	30%
ERCOT	107	52	49%
FRCC	62	29	47%
HI	16	3	19%
MAAC	93	3	3%
MAIN	207	33	16%
MAPP	406	43	11%
NPCC	394	17	4%
SERC	333	94	28%
SPP	262	32	12%
WSCC	773	18	2%
Unknown	3	0	0%
Total	**3,125**	**416**	**13%**

a Numbers may not add up to totals due to independent rounding.
b The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

e. Water body and cooling system type

Table A3-9 shows that most of the existing utility plants with a CWIS and an NPDES permit draw water from a freshwater river (204, or 49 percent). The next most frequent water body types are lakes or reservoirs with 138 plants (33 percent) and estuaries or tidal rivers with 47 plants (11 percent). The table also shows that most of these plants, 314 or 75 percent, employ a once-through cooling system. Of the plants that withdraw from an estuary, the most sensitive type of water body, only nine percent use a recirculating system while 85 percent have a once-through system.

Table A3-9: Number of Existing Utility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type										Total [b]
	Recirculating		Once-Through		Combination		Other		Unknown		
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	4	9%	40	85%	1	2%	2	4%	0	0%	**47**
Ocean	0	0%	15	100%	0	0%	0	0%	0	0%	**15**
Lake/ Reservoir	29	21%	103	75%	4	3%	2	1%	0	0%	**138**
Freshwater River	36	18%	149	73%	8	4%	10	5%	1	0%	**204**
Multiple Freshwater	0	0%	6	60%	3	30%	1	10%	0	0%	**10**
Other/ Unknown	1	50%	1	50%	0	0%	0	0%	0	0%	**2**
Total	**70**	**17%**	**314**	**75%**	**16**	**4%**	**15**	**4%**	**1**	**0%**	**416**

a The number of plants was sample weighted to account for survey non-respondents.
b Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

A3-3.2 Existing Section 316(b) Nonutility Plants

EPA identified nonutility steam electric prime movers that require cooling water using information from the EIA data collection Forms EIA-860B[12] and the section 316(b) Industry Survey. These prime movers include:

- Geothermal Binary (GB)
- Steam Turbine – Fluidized Bed Combustion (SF)
- Solar – Photovoltaic (SO)
- Steam Turbine (ST)

In addition, prime movers that are part of a combined-cycle unit were classified as steam electric.

U.S. DOE, 1998b includes two types of nonutilities: facilities whose primary business activity is the generation of electricity, and manufacturing facilities that operate industrial boilers in addition to their primary manufacturing processes. The discussion of existing section 316(b) nonutilities focuses on those nonutility facilities that generate electricity as their primary line of business.

[12] U.S. DOE, 1998b (Annual Nonutility Electric Generator Report) is the equivalent of U.S. DOE, 1998a for utilities. It is the annual inventory of nonutility plants and collects data on the type of prime mover, nameplate rating, energy source, year of initial commercial operation, and operating status.

Using the identified list of steam electric prime movers, and U.S. DOE, 1999b information on the reported operating status of generating units, EPA identified 559 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Survey determined that 134 of the 559 facilities operate a CWIS and hold an NPDES permit. Table A3-10 provides information on the number of parent entities, nonutility plants, and generating units, and their generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the "section 316(b)" part of the industry.

Table A3-10: Number of Nonutilities, Nonutility Plants, Units, and Capacity, 1999

	Total	Total Steam Electric Nonutilities [a]	Nonutilities with CWIS and NPDES Permit[a,b]	
			Number	% of Steam Electric
Parent Entities	1,509	441	47	11%
Nonutility Plants	2,205	559	134	24%
Nonutility Units	5,958	1,255	343	27%
Nameplate Capacity (MW)	206,500	153,032	107,054	70%

[a] Includes only nonutility plants generating electricity as their primary line of business.
[b] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

a. Ownership type

Nonutility power producers that generate electricity as their main line of business fall into two different categories: "original nonutility plants" and "former utility plants."

❖ *Original nonutility plants*

For the purposes of this analysis, original nonutility plants are those that were originally built by a nonutility. These plants primarily include facilities qualifying under the Public Utility Regulatory Policies Act of 1978 (PURPA), cogeneration facilities, independent power producers, and exempt wholesale generators under the Energy Policy Act of 1992 (EPACT).

EPA identified original nonutility plants with a CWIS and an NPDES permit through the section 316(b) Industry Survey. This profile further differentiates original nonutility plants by their primary Standard Industrial Classification (SIC) code, as reported in the section 316(b) Industry Survey. Reported SIC codes include:

- 4911 – Electric Services
- 4931 – Electric and Other Services Combined
- 4939 – Combination Utilities, Not Elsewhere Classified
- 4953 – Refuse Systems

❖ *Former utility plants*

Former utility plants are those that used to be owned by a utility power producer but have been sold to a nonutility as a result of industry deregulation. These were identified from U.S. DOE, 1999a, by their plant code, section 316(b) Industry Survey, and research conducted through January 2002.[13]

Table A3-11 shows that original nonutilities account for the vast majority of plants (1,894 out of 2,205, or 86 percent). Only 311 out of the 2,205 nonutility plants, or 14 percent, were formerly owned by utilities. However, these 311 facilities account for about 63 percent of all nonutility generating capacity (130,526 MW divided by 206,499 MW). One-hundred thirty-four of

[13] Plants formerly owned by a regulated utility have an identification code number that is less than 10,000 whereas nonutilities have a code number greater than 10,000. When utility plants are sold to nonutilities, they retain their original plant code. EPA tracked ownership changes from utilities to nonutilities, and vice versa, through January 2002. These changes are incorporated into the profile. As such, the universe of facilities (and their corresponding characteristics) is based on EIA 1999 data, adjusted to reflect EPA's most current knowledge.

the 2,205 nonutility plants operate a CWIS and hold an NPDES permit. Most of these section 316(b) facilities (120, or 91 percent) are former utility plants, and account for almost 99 percent of all section 316(b) nonutility capacity (105,672 MW divided by 107,054 MW). The table also shows that only one percent of all original nonutility plants have a CWIS and an NPDES permit,[14] compared to 49 percent of all former utility plants.

Table A3-11: Existing Nonutility Firms, Plants, and Capacity by SIC Code, 1998[a]

SIC Code	Firms			Plants			Capacity (MW)		
	Total Number of Firms[b]	Firms with Plants with CWIS and NPDES[b]		Total Number of Plants	Plants with CWIS and NPDES[b]		Total Capacity	Capacity with CWIS and NPDES[b]	
		Number	% of Total		Number	% of Total		MW	% of Total
Original Nonutilities									
4911	1,428	2	1%	1,894	2	1%	75,973	193	1%
4931		2			2			189	
4939		1			1			505	
4953		3			5			219	
Other SIC		3			3			252	
Former Utility Plants									
n/a	81	36	44%	311	120	39%	130,526	105,672	81%
Total	**1,509**	**47**	**3%**	**2,205**	**134**	**6%**	**206,499**	**107,030**	**52%**

a Numbers may not add up to totals due to independent rounding.
b The number of plants and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

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[14] This percentage understates the true share of section 316(b) nonutility plants because the total number of plants includes industrial boilers while the number of section 316(b) nonutilities does not.

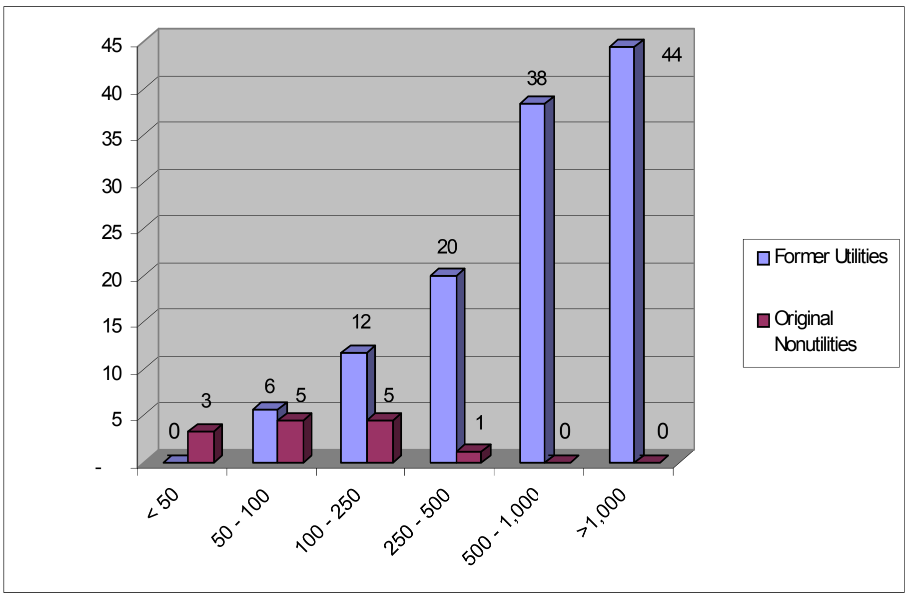
b. Ownership size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of existing section 316(b) nonutility plants owned by small firms. The thresholds used by EPA to determine if a domestic parent entity is small depend on the entity type. Since multiple entity types were analyzed, multiple data sources were needed to determine the entity sizes. EPA found that none of the parent entities of the 134 nonutility plants were small. For a detailed discussion of the identification and size determination of the parent entities please see *Chapter B4: Regulatory Flexibility Analysis.*

c. Plant size

EPA also analyzed the steam electric nonutilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure A3-6 shows that the original nonutility plants are much smaller than the former utility plants. Of the 14 original utility plants, 3 (25 percent) have a total nameplate capacity of 50 MW or less, and 8 (58 percent) have a capacity of 100 MW or less. No original nonutility plant has a capacity of more than 500 MW. In contrast, only 18 (15 percent) former utility plants are smaller than 250 MW while 83 (69 percent) are larger than 500 MW and 44 (37 percent) are larger than 1,000 MW.

Figure A3-6: Number of Existing Nonutility Plants with CWIS and NPDES Permit by Generating Capacity (in MW), 1998[a,b]



[a] Numbers may not add up to totals due to independent rounding.
[a] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

d. Geographic distribution

Table A3-12 shows the distribution of existing section 316(b) nonutility plants by NERC region. The table shows that the Northeast Power Coordinating Council (NPCC) has the highest absolute number of existing section 316(b) nonutility plants with 45 (9 percent) of the 134 plants with a CWIS and an NPDES permit, followed by the Mid-Atlantic Area Council (MAAC) with 41 plants. MAAC also has the largest percentage of plants with a CWIS and an NPDES permit compared to all nonutility plants within the region, at 26 percent.[15]

Table A3-12: Nonutility Plants by NERC Region, 1998

NERC Region	Total Number of Plants	Plants with CWIS & NPDES Permit[a,b]	
		Number	% of Total
ASCC	26	0	0%
ECAR	139	10	7%
ERCOT	75	0	0%
FRCC	57	1	2%
HI	11	0	0%
MAAC	155	41	26%
MAIN	136	18	13%
MAPP	70	1	2%
NPCC	531	45	9%
SERC	279	1	0%
SPP	43	0	0%
WSCC	613	16	3%
Not Available	70	0	0%
Total	**2,205**	**134**	**6%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

[15] As explained earlier, the total number of plants includes industrial boilers while the number of plants with a CWIS and an NPDES permit does not. Therefore, the percentages are likely higher than presented.

e. Water body and cooling system type

Table A3-13 shows the distribution of existing section 316(b) nonutility plants by type of water body and cooling system. The table shows that for both original and former nonutilities, a majority of plants with a CWIS and an NPDES permit draw water from either a freshwater river, or an estuary or tidal river. Out of the 14 total original nonutilities, seven (50 percent) pull from a freshwater river, and six (42 percent) pull from an estuary or tidal river. Out of the 120 former utilities, 53 (44 percent) pull from a freshwater river, and 47 (39 percent) pull from an estuary or tidal river.

The table also shows that most of the nonutilities employ a once-through system: 13 out of 14 plants (92 percent) for original nonutilities and 101 out of 120 (84 percent) for former nonutility plants. Of the plants that withdraw from an estuary/tidal river, the most sensitive type of waterbody, only two use a recirculating system, while 50 (94 percent) operate a once-through system.

Table A3-13: Number of Nonutility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type								
	Recirculating		Once-Through		Combination		Other		Total [b]
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Original Nonutilities									
Estuary/ Tidal River	0	0%	6	100%	0	0%	0	0%	6
Ocean	0	0%	0	0%	0	0%	0	0%	0
Lake/ Reservoir	0	0%	0	0%	1	100%	0	0%	1
Freshwater River	0	0%	7	100%	0	0%	0	0%	7
Other/ Unknown	0	0%	0	0%	0	0%	0	0%	0
Total	**0**	**0%**	**13**	**92%**	**1**	**8%**	**0**	**0%**	**14**
Former Utility Plants									
Estuary/ Tidal River	2	4%	50	94%	1	2%	0	0%	53
Ocean	0	0%	9	100%	0	0%	0	0%	9
Lake/ Reservoir	2	19%	9	81%	0	0%	0	0%	11
Freshwater River	13	29%	32	71%	0	0%	1	2%	46
Other/ Unknown	0	0%	1	100%	0	0%	0	0%	1
Total	**17**	**14%**	**101**	**84%**	**1**	**1%**	**1**	**1%**	**120**

[a] The number of plants was sample weighted to account for survey non-respondents.
[b] Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

A3-4 INDUSTRY OUTLOOK

This section discusses industry trends that are currently affecting the structure of the electric power industry and may therefore affect the magnitude of impacts from the proposed section 316(b) Phase II Rule. The most important change in the electric power industry is deregulation – the transition from a highly regulated monopolistic to a less regulated, more competitive industry. Subsection 3.4.1 discusses the current status of deregulation. Subsection 3.4.2 presents a summary of forecasts from the Annual Energy Outlook 2002.

A3-4.1 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.[16] The industry has traditionally 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. Today, the relationship between electricity consumers and suppliers is undergoing substantial change. Some states have implemented plans that will change the procurement and pricing of electricity significantly, and many more plan to do so during the first few years of the 21st century (Beamon, 1998).

a. Key changes in the industry's structure

Industry deregulation already has changed and continues to fundamentally change the structure of the electric power industry. Some of the key changes 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, federal and state policies have led to increased competition in the generation sector of the industry. Increased competition has 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. 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).

b. 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 are proposing to form Independent System Operators (ISOs) to operate the transmission grid, regional transmission groups, 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

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[16] 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).

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.

c. State activities

Many states have taken steps to promote competition in their electricity markets. The status of these efforts varies across states. Some states are just beginning to study what a competitive electricity market might mean; others are beginning pilot programs; still others have designed restructured electricity markets and passed enabling legislation. However, the difficult transition to a competitive electricity market in California, characterized by price spikes and rolling black-outs, has affected restructuring in that state and several others. Since those difficulties in 2000, a total of seven states (Arkansas, Montana, Nevada, New Mexico, Oklahoma, Oregon, and West Virginia) have delayed the restructuring process pending further review of the issues while California has suspended direct retail access. As of March 2002, the following states have either enacted restructuring legislation or issued a regulatory order to implement retail access (U.S. DOE, 2002):

- Arizona
- Connecticut
- Delaware
- District of Columbia
- Illinois
- Maine
- Maryland
- Massachusetts
- Michigan
- New Hampshire
- New Jersey
- New York
- Ohio
- Pennsylvania
- Rhode Island
- Texas
- Virginia

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 market structures required to ensure that the benefits of competition flow to all consumers (Beamon, 1998).

A3-4.2 Energy Market Model Forecasts

This section discusses forecasts of electric energy supply, demand, and prices based on data and modeling by the EIA and presented in the *Annual Energy Outlook 2002* (U.S. DOE, 2001)]. The EIA models future market conditions through the year 2020, 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 EIA's National Energy Modeling System (NEMS) using assumptions reflecting economic conditions as of July 2001. EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the proposed section 316(b) Phase II Rule (see *Chapter B3: Electricity Market Model Analysis*). The IPM generates baseline and post compliance estimates of each of the measures discussed below. For purposes of comparison, this section presents a discussion of EIA's reference case results.

a. Electricity demand

The AEO2002 projects electricity demand to grow by approximately 1.8 percent annually between 2000 and 2020. This growth is driven by an estimated 2.3 percent annual increase in the demand for electricity from the commercial sector associated with a projected annual growth in commercial floor space. Residential demand is expected to increase by 1.7 percent annually as a result of an increase in the number of U.S. households of 1 percent per year between 2000 and 2020. EIA expects electricity demand from the industrial sector to increase by 1.4 percent annually over the same forecast period, largely in response to an increase in industrial output of 2.6 per year.

b. Capacity retirements

The AOE2002 projects total nuclear capacity to decline by an estimated 10 percent (or 10 gigawatts) between 2000 and 2020 due to nuclear power plant retirement. These closures are primarily assumed to be the result of the high costs of maintaining the performance of nuclear units compared with the cost of constructing the least cost alternative. EIA also expects total fossil fuel-fired generation capacity to decline due to retirements. EIA forecasrs that total fossil-steam capacity will decrease by an estimated 7 percent (or 37 gigawatts) over the same time period including 20 gigawatts of oil and natural gas fired steam capacity.

c. Capacity additions

Additional generation capacity will be needed to meet the estimated growth in electricity demand and offset the retirement of existing capacity. EIA expects utilities to employ other options, such as life extensions and repowering, to power imports from Canada and Mexico, and purchases from cogenerators before building new capacity. EIA forecasts that utilities will choose technologies for new generation capacity that seek to minimize cost while meeting environmental and emission constraints. Of the new capacity forecasted to come on-line between 2000 and 2020, 88 percent 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 nine percent of the additional capacity forecasted to come on line between 2000 and 2020 is expected to be provided by new coal-fired plants, while the remaining three percent is forecasted to come from renewable technologies.

d. Electricity generation

The AEO2002 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 2000 and 2020, its share of total generation is expected to decrease from 52 percent to an estimated 46 percent. This decrease in the share of coal generation is in favor of less capital-intensive and more efficient natural gas generation technologies. Investment in existing nuclear plants is expected to hold nuclear generation at current levels until 2006, after which it is forecast to decline as older units are retired. The share of total generation associated with gas-fired technologies is projected to increase from approximately 16 percent in 2001 to an estimated 32 percent in 2020, replacing nuclear power as the second largest source of electricity generation. Generation from oil-fired plants is expected to remain fairly small throughout the forecast period.

e. Electricity prices

EIA expects the average price of electricity, as well as the price paid by customers in each sector (residential, commercial, and industrial), to decrease between 2000 and 2020 as a result of competition among electricity suppliers. Specific market restructuring plans differ from state to state. Some states have begun deregulating their electricity markets; EIA expects most states to phase in increased customer access to electricity suppliers. Increases in the cost of fuels like natural gas and oil are not expected to increase electricity prices; these increases are expected to be offset by reductions in the price of other fuels and shifts to more efficient generating technologies.

GLOSSARY

Baseload: 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.
(http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Combined-Cycle Turbine: 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 portion of an electric system that is dedicated to delivering electric energy to an end user.

Electricity Available to Consumers: Power available for sale to customers. Approximately 8 to 9 percent 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 on the wholesale electric power business.

Gas Combustion 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.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than baseload but less than peakload. Intermediate-load units are used during the transition between baseload and peak load requirements.
(http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

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.

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

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.

Net 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, exclusive of station use, and unspecified conditions for a given time interval.

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.
(http://www.eia.doe.gov/emeu/iea/glossary.html)

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

Peakload: A peakload generating unit, normally the least efficient of the three unit types, is used to meet requirements during the periods of greatest, or peak, load on the system. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Power Marketers: Business entities 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. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Power Brokers: 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. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Prime Movers: 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. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

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 Costs: The difference between revenues under competition and costs of providing service, including the inherited fixed costs from the previous regulated market. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

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. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Water Turbine: A unit in which the turbine generator is driven by falling water.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under the pressure of 1 volt at unity power factor.(Does not appear in text)

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or take from, an electric circuit steadily for 1 hour. (Does not appear in text)

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