Kirk-Othmer Encyclopedia of Chemical Technology.

REGULATORY AGENCIES, POWER GENERATION

Entities involved in the generation of electric power in the United States are subject to regulation by numerous state and federal agencies. As with other industrial processes, there are a plethora of environmental regulations and laws in place, designed to ensure that the generation and delivery of electric power have minimal impact on air, land, and water resources. These regulations and laws are also designed to protect the welfare of the ecosystem, public health, and overall quality of life.

In addition to environmental regulation, there are many laws and regulations in place that are designed to ensure fair business practices, a stable energy supply, and consumer protection. However, some of the key regulatory issues impacting the industry are likely to change by the year 2000 as environmental regulation continues to become more stringent and business-practice regulation undergoes a significant transition when more competition is introduced into the power market.

The Federal Energy Regulatory Commission (FERC), an independent agency of the U.S. government, has regulatory oversight of the country's electric utilities, natural gas pipeline transportation system, oil pipeline transportation system, and most U.S. hydroelectric generation facilities (1). More specifically, in the power generation sector, FERC administers laws and regulations involving critical energy issues, including transmission and wholesale sales of electric energy in interstate commerce; licensing and inspection of private, municipal, and state hydroelectric projects; and oversight of related environmental matters.

FERC was created in October 1977 as a result of the passage of the Department of Energy Organization Act. At that time, the 57-year-old Federal Power Commission (FPC) was eliminated and FERC took over many of the FPC's responsibilities.

1. History of Electric Utility Business Regulation

The history of regulation (1–4) in the United States sheds light on the current situation. Thomas Edison's Pearl Street Generating Station went into business in 1882, marking the start of the U.S. electric utility industry. It was the first U.S. power plant and served 85 customers, lighting 400 lights in downtown Manhattan near New York City's financial district. As the industry developed over the following decade, it became apparent that building more than one utility system, including power plants, substations, and transmission and distribution networks, in a given area was not economical. It was also apparent that there were economies of scale associated with using large central generating stations to serve a large customer base. There were also many niche markets for smaller power plants which could be sited at or near industrial loads. By 1900, such plants represented more than half of the country's installed generating capacity. However, electric utility plants accounted for more than 85% of the country's installed generating capacity by 1950, and more than 90% by 1993.

Utility systems were extremely capital-intensive and investors needed to know that a stable customer base could be secured. Thus, electric companies typically secured rights to franchise territories. At the turn of the century, franchises were usually granted by city councils and local politicians. Because the franchises were granted and controlled by these partisan groups, they were also subject to the instability associated with ever-changing leaderships. Graft and favoritism associated with franchise awards were not uncommon. In some areas, municipal-owned systems were developed to help overcome the problems associated with granting service territories and to help ensure a stable, low cost power supply.

By 1907, both utilities and consumers were speaking out in favor of establishing state regulation that would put the power of utility oversight in the hands of nonpartisan agencies. In that year, three states formed regulatory agencies; by 1916, 33 states had regulatory agencies. These agencies treated utilities as natural monopolies. Because only one utility could economically serve a given area, state regulators would set the electric companies' rates to ensure that consumers had an affordable power supply. The rates were also designed to ensure that the utility received a fair return on investment, a factor that stabilized the industry and enabled utilities to secure the long-term financing that was a necessity for growth.

Between 1900 and 1930, the electric power industry grew rapidly in the United States. As electricity became less expensive and widely available, new uses for electric power were continually developed. During this time period, the principal players in the utility business formed large holding companies that controlled numerous subsidiaries, including electric power equipment suppliers, engineering and construction firms involved with utility system design and construction, project finance companies, and system/plant operating companies. Some of the holding companies were used to shift profits away from the state-regulated utilities that operated plants and sold power. For example, the unregulated holding company would overcharge its utility subsidiary for arranging project financing and providing engineering and construction services.

The excesses of several of the holding companies attracted the attention of government leaders and, in 1928, the Federal Trade Commission (FTC) began investigating the holding companies. This led to the Public Utility Act of 1935, which amended the earlier Federal Water Power Act of 1920 and expanded the duties of the Federal Power Commission under the newly amended Federal Power Act to include regulation of electric utility wholesale and transmission rates and transactions. It also required interstate holding companies to register with the Securities and Exchange Commission (SEC) and to operate according to the SEC's rules, and that certain holding companies be broken up by the SEC.

The next significant change in federal regulations affecting the entire U.S. power industry did not occur until after the FPC was replaced by the Federal Energy Regulatory Commission in the 1970s. In the wake of the energy crisis, Congress passed the Public Utility Regulatory Policies Act of 1978 (PURPA) as part of the National Energy Act of 1978. PURPA aimed to increase conservation of energy and improve the efficiency of the use of facilities and resources by electric utilities. It called for state regulatory authorities to encourage conservation and utility efficiency and to provide for equitable rates. Some of PURPA's provisions were designed to encourage the development of cogeneration and small power production facilities, typically located at industrial facilities, by loosening the economic, regulatory, and institutional barriers that discouraged cogeneration and the use of renewable energy resources.

Obstacles previously faced by nonutility generators (NUGs) before PURPA included (*1*) utilities typically had no incentive to pay NUGs attractive rates for their power output because the unregulated NUGs usually represented competition for utilities, particularly for large industrial loads; (*2*) some utilities charged high rates for backup power services to NUGs; and (*3*) a NUG wishing to sell power into an electric utility's system risked being considered a utility itself and could be subject to extensive federal and state regulation.

In 1986, Congress passed the Electric Consumers Protection Act (ECPA), which set the foundation for more efficient relicensing of hydropower facilities, enhanced competition among applicants for relicensing, and ensured a balance between environmental interests and the need for hydropower development.

Comprehensive changes to power industry regulation are underway in the 1990s as a result of Congress' passage of the Energy Policy Act (EPACT) of 1992, which includes provisions designed to foster competition through regulatory reform in both the oil pipeline and electric utility industries. EPACT also amends the 1935 Public Utility Act, which was designed to discourage holding companies structured to hamper effective state regulation. Although its implementation is still being negotiated (1996) by federal and state government as well as industry groups, EPACT is likely to impact the power industry in three ways. First, EPACT allows

FERC to order upon application wholesale, but not retail, transmission line access. Again, EPACT thus aims to promote wholesale power competition. Second, EPACT establishes a program for providing federal support on a competitive basis for renewable energy technologies. It also expands a program to promote the export of renewable technologies to emerging markets in developing countries. Third, a class of power generation entities known as exempt wholesale generator (EWG) has been created. EWGs, which may be owned by either utilities or nonutilities, are exempt from the corporate organizational restrictions of the 1935 PUHCA. EPACT thus aims to remove obstacles to wholesale power competition that are included in PUHCA.

2. Federal Energy Regulatory Commission

2.1. Organization

FERC has five members who are appointed by the President of the United States, with the advice and consent of the U.S. Senate, to five-year staggered terms. Each commissioner has an equal vote on regulatory matters. No more than three commissioners may belong to the same political party. One member is designated by the President to serve as chairperson and is the commission's administrative head. The commission generally meets publicly twice per month to discuss agency business, including setting of industrywide rules and consideration of license applications, rate filings, and other matters submitted by regulatory entities.

FERC regulates the sale of electric energy at wholesale and the transmission of electric energy in interstate commerce by public utilities under the Federal Power Act, but the retail sale of electricity, ie, sales to end-use customers such as homeowners and businesses by public utilities, is generally regulated by state public utility commissions pursuant to state laws. Sales of electricity for resale (FERC's regulatory domain) represent approximately 25% of total electric sales by investor-owned utilities in the United States. When a public utility files for rate changes or modifications to its terms or conditions of electric service, the commission issues a public notice, listed in the *Federal Register,* soliciting comments, protests, and interventions. Approximately 85% of the Commission's rate filings are processed by FERC staff members through delegated authority. The commission itself handles only major rate increase requests and contested applications, and, pursuant to the Federal Power Act, acts on these requests and applications by either accepting all or part of an application, rejecting all or part of an application, or suspending the effectiveness of the application and ordering a hearing and investigation.

The commission authorizes the sale, lease, or disposition of certain utility facilities, mergers or consolidation of such facilities (mergers), and certain security issuances (financial instruments) by public utilities. Under the Federal Power Act, FERC also reviews the relationships of officers and boards of directors of utilities to other utilities, firms supplying electrical equipment to the utilities, or firms underwriting securities. Finally, under separate statutory authority, FERC reviews rates charged by the federal power marketing administrations and, pursuant to PURPA and EPACT, certifies small power production and cogeneration facilities, ie, entities defined by PURPA, as well as exempt wholesale generators, ie, entities defined by EPACT.

In the hydroelectric area, pursuant to the Federal Power Act as amended, FERC's responsibilities include project licensing, dam safety, project compliance, investigation and assessment of headwater benefits, environmental issues, and interagency coordination. FERC engineers perform periodic safety inspections of hydroelectric power facilities. These inspections emphasize the evaluation of structural integrity of hydro plant structures. The commission's licensing costs are offset by annual charges to the license holders. Finally, FERC determines charges for the use of certain federal lands and dams as well as Native American reservations.

2.2. Policies and Rulemaking

In March of 1995, FERC proposed sweeping changes in the electric utility industry. At that time, FERC declared that "monopoly control of the nation's transmission system is the single greatest impediment to wholesale competition" for electric power sales (5), and released a Notice of Proposed Rulemaking (NOPR) seeking comments on FERC's proposals to encourage a more fully competitive wholesale electric power market. The proposed rule would require utilities under FERC jurisdiction that own or control transmission facilities in interstate commerce to file tariffs under which they will provide service to third parties seeking access to the system, ie, for transport of electric power. The rule also requires utilities under FERC jurisdiction to offer to eligible customers transmission service comparable to the service they provide themselves, and to take service under the same tariffs for their own wholesale sales and purchases of electric energy.

The proposed rule includes two *pro forma* tariffs, one for network service and one for point-to-point service, setting out the minimum terms and conditions which the utility must offer. These terms and conditions specifically cite access to ancillary services, including scheduling and dispatching, load following, imbalance resolution, reactive power support, loss compensation, and system protection. In addition, the proposal includes requirements for utilities to enlarge their transmission capacity and expand ancillary services as needed for requested transmission access. The proposed rule also states that a public utility must obtain transmission services, including ancillary services, for all of its new wholesale sales and purchases of electric energy under the same tariff with which it offers such services to others, and a transmission owner's tariff must include separately stated rates for transmission and ancillary service components. Also, a public utility must rely on the same electronic information network that its customers use to obtain transmission information about its system when buying or selling power.

FERC's March 1995 NOPR has been the subject of much controversy and debate. State regulatory commissions are struggling to determine how to regulate a restructured power industry. Electric utilities are lobbying to ensure that they are fully reimbursed for any stranded assets, ie, assets rendered uneconomic, as a result of FERC's proposed rules. For instance, a large industrial customer may choose to purchase power from an entity other than its traditional utility provider, much like choosing a different long-distance telephone service provider. As a result of the loss of these large customers, a utility may be saddled with large generation facilities that are no longer economic to operate. The utilities maintain that they should be compensated for losses in such cases because the facilities were financed and built under the premise that a guaranteed return on investment could be expected because of the existing regulatory environment.

Entities involved in long-term contracts with electric utilities, such as fuel suppliers and NUGs selling power to utilities, also have concerns that some utilities or industrial customers will not be able to honor their contracts under the new, more competitive system. Finally, some utilities are concerned that they will not be adequately reimbursed for opening up their transmission systems to competitors. The potential competitors in turn are concerned that utilities will not provide unbiased access to their transmission systems if the utilities themselves are also in business of marketing power. There has also been some debate regarding which transmission facilities are eligible for open access. This is because some facilities are considered local distribution systems by utilities, which feel they should not be opened to competitors.

FERC believes that 137 utilities will be required to open up their transmission networks. As of mid-1996, the NOPR is still being debated. However, several states have adopted preliminary plans to open up the transmission networks of their regulated utilities by the year 2000 or shortly thereafter.

3. Environmental Regulations

The electric power industry is subject to many of the same environmental regulations and laws affecting other process industries which have the potential to generate waste streams (see Regulatory agencies). The main agencies involved in the environmental regulation of power generation facilities are the Environmental Protection Agency (EPA), the Nuclear Regulatory Commission (NRC), and the Occupational Safety and Health Administration (OSHA). Because power generation can potentially impact all aspects of the environment, there are volumes of regulations dictating what emissions levels are allowable, including airborne pollutants, solid and liquid wastes, noise, and inert discharges such as water. There are also many regulations that impact where a power plant can be sited and how it must be designed to minimize its impact on the surrounding environment. In many cases, federal agencies set national standards which individual states must implement. In addition, state-specific regulations for pollution control are often more stringent than federal regulations. For specific information about environmental regulations affecting a given geographic area, readers should consult the local office of their state department of environmental protection, the appropriate regional environmental commission, or the local EPA office.

The Clean Air Act of 1970 was the first federal environmental legislation to affect significantly the electric power industry. It was in that year that the Environmental Protection Agency was empowered to set enforceable air quality standards. However, Congress had previously passed the Clean Air Act (CAA) of 1963 in response to growing concerns about airborne power plant exhaust emissions of sulfur dioxide, SO_2, which is a precursor of acid rain containing sulfuric acid, and oxides of nitrogen, NO_x, which is a principal contributor to low level ozone, ie, smog, and a lesser contributor to acid rain containing nitric acid (4). Prior to 1970, SO_2 regulations were focused on reducing ground-level SO_2 emissions to prevent associated impacts to human health. This is one of the reasons for using tall exhaust gas stacks, which help disperse airborne emissions high into the atmosphere to minimize terrestrial impacts.

In 1971, EPA established New Source Performance Standards (NSPS), which required coal-fired utility boilers built after August 17, 1971 to emit no more than 0.52 kg $SO_2/10^6$ kJ (1.2 lb of $SO_2/10^6$ Btu) of fuel heating value input. Requirements for NO_x ranged from 0.086–0.34 kg/10^6 kJ (0.2–0.8 lb/10^6 Btu) of fuel input, depending on the type of fuel burned and the combustion device used.

In 1977, Congress amended the CAA to require states to set limits on existing sources in regions not attaining goals established in the CAA of 1970. In 1979, EPA established the Revised New Source Performance Standards (RNSPS), which retained the 1971 NSPS of 0.52 kg/10^6 kJ for SO_2 emissions, but required SO_2 emissions from all new or modified boilers (post-1978) to be reduced by at least 90%, unless emissions could be cut to 0.26 kg/10^6 kJ (0.6 lb/10^6 Btu) at less than 90% removal. In those cases, 70–90% removal are permitted, depending on the sulfur content of the coal. RNSPS for NO_x are more complex. As with NSPS levels, RNSPS NO_x requirements varied from 0.086–0.34 kg/10^6 kJ, depending on fuel content and the combustion technology used. However, RNSPS for NO_x delineate the combustion devices into more categories.

3.1. Clean Air Act Amendments of 1990

The primary aspects of the Clean Air Act Amendments (CAAA) of 1990, which impact electricity producers, include a 10 million ton (short ton) reduction in national SO_2 emissions and a two million ton reduction in NO_x emissions from 1980 levels (Tables 1 and 2). The reduction in SO_2 is occurring in two phases. Phase I began in 1995 and Phase II begins in 2000. The CAA established an innovative program whereby companies could purchase and trade allowances for SO_2 and NO_x emissions as one means of meeting the new limits. In the power generation sector, the CAAA focus mainly on electric-utility-owned generation capacity.

3.2. Sulfur Dioxide Control

Title 4 of the CAAA has the primary goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. A national cap on SO_2 emissions of 15 million tons per year has been imposed, including 8.95 million tons/yr for utilities and 5.6 million tons/yr for industrial sources (8). To achieve such reductions, a two-phase

Table 1. Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at U.S. Electric Utilities, 10^3 t[a]

Emission[b]	1989	1990	1991	1992	1993
sulfur dioxide, SO_2	14,297	13,943	13,619	13,318	13,093
nitrogen oxides, NO_x	5,403	5,263	5,263	5,147	5,309
carbon dioxide, CO_2	1,739,652	1,700,232	1,704,483	1,690,441	1,765,653

[a]Refs. 6 and 7.
[b]Estimates for 1993 are preliminary; for prior years are final. Estimates are for steam-electric plants ≥ 10 MW, based on fuel consumption data.

Table 2. 1993 Estimated Emissions from Fossil-Fueled Steam-Electric Generating Units at Electric Utilities by Census Division, 10^3 t[a, b]

	Coal			Petroleum			Gas[c]		Other[d]		
Census division state	Sulfur dioxide	Nitrogen oxides	Carbon dioxide	Sulfur dioxide	Nitrogen oxides[e]	Carbon dioxide	Nitrogen oxides	Carbon dioxide	Sulfur dioxide[f]	Nitrogen oxides[g]	Carbon dioxide[h]
New England[i]	119	47	15,286	107	21	13,551	6	1,681	1	1	969
Middle Atlantic[j]	1,383	347	130,307	87	28	19,594	31	12,893			45
East North Central[k]	4,661	1,453	392,429	8	3	2,230	6	2,138	1	1	785
West North Central[l]	1,016	649	188,637	2		315	7	1,882	1	1	1,098
South Atlantic[m]	3,050	941	334,732	297	65	37,523	32	9,853	1		292
East South Central[n]	2,297	677	219,866	53	6	3,292	5	1,756	0	0	0
West South Central[o]	783	622	215,416	3	1	729	254	85,476	0	0	0
Mountain[p]	452	508	201,553	1	1	403	11	3,880	0		
Pacific contiguous[q]	83	45	13,447	4	3	1,738	71	27,024			690
Pacific noncontiguous[r]	1	0	0	20	9	4,754	0	0	0	0	0
Total	*13,844*	*5,288*	*1,711,673*	*583*	*136*	*84,129*	*424*	*146,584*	*4*	*4*	*3,880*

[a]Refs. 6 and 7.
[b]Estimates for 1993 are preliminary. Estimates are for steam-electric plants ≥ 10 MW, based on fuel consumption data.
[c]Except for Pacific noncontiguous, which has a value of zero, sulfur dioxide emissions for all other census divisions are <0.5; total sulfur dioxide value $= 1$.
[d]Includes light oil, methane, coal–oil mixture, propane gas, blast furnace gas, wood, and refuse.
[e]Emission value is <0.5 for West North Central.
[f]Emission value is <0.5 for Middle Atlantic and Pacific contiguous.
[g]Emission value is <0.5 for Middle Atlantic, South Atlantic, Mountain, and Pacific contiguous.
[h]Emission value is <0.5 for Mountain.
[i]Includes Conn., Maine, Mass., N.H., R.I., and Vt.
[j]Includes N.J., N.Y., and Pa.
[k]Includes Ill., Ind., Mich., Ohio, and Wis.
[l]Includes Iowa, Kans., Minn., Mo., Nebr., N.D., and S.D.
[m]Includes Del., D.C., Fla., Ga., Md., N.C., S.C., Va., and W. Va.
[n]Includes Ala., Ky., Miss., and Tenn.
[o]Includes Ark., La., Okla., and Tex.
[p]Includes Ariz., Colo., Idaho, Mont., Nev., N. Mex., Utah, and Wyo.
[q]Includes Calif., Oreg., and Wash.
[r]Includes Alaska and Hawaii.

compliance plan was established. Phase I, effective January 1, 1995, impacts 110 large coal-fired plants, comprising 261 separate units and representing approximately 89,000 MW of capacity or over 10% of the country's installed capacity. These facilities are located in 21 eastern and midwestern states. Owners of these units were given the option of meeting the new requirements by any of the following means: installing SO_2 emissions control devices such as wet flue gas desulfurization systems; switching to lower sulfur fuel; applying to EPA to substitute control of other units to attain the required emissions reductions; and obtaining additional emissions allowances by overcontrolling emissions from one or more units.

Utilities that reduce emissions below the number of allowances they hold may trade emissions credits on the open market. Owners of plants affected by Phase I regulations can also petition the EPA for a two-year extension for meeting Phase I emissions if they have selected a control option capable of reducing SO_2 emissions by 90% or more, such as is capable by flue-gas desulfurization. Owners of these units can receive bonus allowances for 1997–1999 if they have operated at SO_2 emissions below 0.52 kg/10^6 kJ (1.2 lb/10^6 Btu) of fuel heating value input.

Phase II of the Title 4 of the CAAA begins in the year 2000, which aims to tighten emissions down on all existing utility-owned oil- and coal-fired units larger than 25 MW and all new utility plants. Starting in 2000, units that have been in operation since before 1985 will be required to lower emissions to the lesser of either 0.52 kg/10^6 kJ for SO_2 emissions or whatever their existing NSPS requirement was. However, special allowances will be provided for certain units that were previously fueled by oil or gas, that started operation between 1985 and 1996, that operated at lower capacity factors in the mid-1980s, that are part of small utility systems or located in states having historically low emissions rates, that are part of certain municipal systems, or that are located in Florida or 10 other listed states (9).

Any units that started operation after December 31, 1995 not only received no allowances, but were required to purchase them to offset emissions. Certain units may be eligible for a four-year extension for meeting Phase II SO_2 emissions limits. To be eligible, a plan must be in place before January 1998 to repower the affected facility using one of a listed group of clean coal repowering technologies. In this case, repowering refers to the replacement of a plant's existing boiler with some other advanced, low emission combustion system, such as a fluidized-bed boiler or an integrated gasification/combined-cycle unit (see Power generation).

3.3. CAAA Impact on Nonutility Power Producers

The SO_2 and NO_x regulations being implemented as part of the CAAA of 1990 primarily target electric utility power plants. However, under Phase II of the CAAA, nonutility power producers will be required to acquire emissions allowances for any SO_2 being emitted from new facilities. Although industrial emitters of SO_2 and NO_x are not directly affected, the EPA did undertake a study to estimate what contribution industrial producers have on annual estimated SO_2 production in the United States (10). The report found that annual industrial SO_2 emissions would remain below the predetermined critical limit of 5.6×10^6 tons/yr until at least 2015 (10). Thus, the agency recommended no new controls for industrial SO_2 emissions at this time.

Nonutility generators can be affected by parts of the CAAA's NO_x reduction measures. This impact will vary, depending on what state a nonutility generator is located in, what technology is employed, and what fuel is burned. Title 1 of the 1990 CAAA targets NO_x reductions in approximately 100 different geographic areas of the United States where national ambient air quality standards for ground-level ozone are being exceeded.

3.4. NO_x Control

NO_x control limitations are described in both Title 1 and Title 4 of the CAAA of 1990. Title 4 requirements affect only coal-fired boilers and take effect at the same time that the boilers are impacted by CAAA SO_2 requirements. As of 1996, EPA had established Title 4 NO_x limits only for tangentially fired and wall-fired, dry-bottom boilers that would be impacted by Phase I of the CAAA SO_2 regulations (Title 4). Limits of 0.22

kg/10^6 kJ (0.5 lb/10^6 Btu) and 0.19 kg/10^6 kJ (0.45 lb/10^6 Btu) have been set for wall-fired and tangentially fired units, respectively. The EPA based these levels on what was achievable using low NO_x burners. However, plants can employ a number of different front- or back-end emissions controls, including a combination of options, to achieve these levels. EPA plans to announce Title 4 NO_x requirements for 300 additional boilers by late 1996 or early 1997.

Title 1 of the CAAA of 1990 focuses on utility units located in ozone nonattainment regions of the United States, which include approximately 100 different areas where national standards for ground-level ozone (O_3) are exceeded. More than 900 utility boilers are located within the nonattainment zones, including 90 units impacted by Phase I of Title 4. These boilers represent approximately 400,000 MW of installed capacity and 60% of the country's utility boilers.

The impacts of Title 1 of the CAAA vary, depending on how serious the nonattainment problem is in a given area. In areas where the degree of nonattainment is more severe, local or regional NO_x requirements are typically more stringent.

In each region, states are developing implementation plans to achieve compliance for ground-level ozone. EPA has provided a framework for guiding the states. For example, starting in November 1992, all major new sources of NO_x were required to meet permit limits representing lowest achievable emissions rates (LAER). In addition, NO_x emissions from any new units must be offset, to varying degrees, by reductions in NO_x made elsewhere. The definition of a major source varies, depending on the severity of the ozone problem. For example, in the Los Angeles area, which is considered one of the country's most extreme areas for ozone nonattainment and in which O_3 levels in the air exceed 0.28 ppm, a major source is considered any unit producing NO_x at a rate of 10 tons/yr or more. In contrast, in moderate nonattainment areas, such as parts of Arizona and southeast Florida, where O_3 levels range from 0.139–0.160 ppm, a major new source is a producer adding more than 100 tons/yr.

Starting in May 1995, all existing major NO_x sources located in ozone noncompliance areas were required to employ reasonably available control technologies (RACT) for NO_x control. Under EPA regulatory supervision, states are responsible for determining what specific technologies are considered RACT for a given type of plant and what specific emissions regulations limits should be. In many cases, states have adopted regulations that are tighter than those suggested by the EPA. As of 1996, information on state-specific RACT programs is still being compiled. However, a variety of technologies have been applied on utility boilers to meet the first phase of NO_x reductions, including low NO_x burner retrofits, flue-gas recirculation, natural gas cofiring, combustion air modifications, and selective noncatalytic reduction (SNCR). On gas turbine-based plants, NO_x compliance options have included low NO_x burner retrofits, water or steam injection, SNCR, and selective catalytic reduction (SCR).

Because of the necessity to comply with national standards for ground-level ozone, some states are planning another phase of more stringent NO_x emissions limits which may take place in the early 2000s. These additional post-RACT reductions may affect plants of all sizes and types, but are likely to focus on major sources. The deadline for compliance in the most extreme areas is 2010. For severe nonattainment areas (O_3 levels 0.181–0.280 ppm), including many coastal areas in the Northeast, from northern Virginia to southern Maine, compliance must be achieved by November 2005 to November 2007. Serious ozone nonattainment areas (O_3 levels 0.161–0.180 ppm) are expected to be in compliance by November 1999. Moderate noncompliance areas must comply by November 1996.

3.5. Hazardous Air Pollutants

Title 3 of the CAAA of 1990 addresses the release of hazardous air pollutants (HAPs) by requiring both the identification of major stationary sources and area source categories for 189 toxic chemicals and the promulgation of control standards. Major sources of air toxics, also referred to as HAPs, include any stationary source or group of sources emitting 10 or more tons/yr of any single listed toxic chemical or 25 tons/yr of a combination of any listed toxic. Area sources of HAPs include smaller plants that emit less than the 10 or 20 tons/yr thresholds. The major sources of HAPs are typically industrial facilities. However, Title 3 requires the EPA to study potential health affects associated with emissions of HAPs from electric utility boilers (11).

EPA is also required to recommend maximum achievable control technologies (MACT) for reducing HAPs from new and existing major and area sources to be achieved by 2000. After that time, additional control measures may also be considered. As of 1996, EPA has recommended no new HAP for power boilers. However, both utility and nonutility power generators are keeping a close watch out for possible future regulations for certain HAPs, including mercury and hydrogen chloride.

3.6. Other Emissions

Title 3 of the CAAA also impacts power plant particulate matter (ash) emissions. In June of 1994, the EPA actually relaxed its standards for emissions of particulate smaller than 10 micrometers (PM10). This revision was in response to the EPA's mandate to review health-based pollution standards every five years (12). However, it is uncertain as of this writing (1996) if states will indeed implement less stringent regulations for PM10 emissions.

The CAAA also established a requirement that major new or modified sources of PM10 or carbon monoxide (CO) located in ozone nonattainment areas must obtain emissions offsets from areas of equal or worse nonattainment before construction of such facilities is approved. There are already regulations in place, including the Clean Drinking Water Act and the Resource Conservation and Recovery Act, which limit the discharge of toxics in solid and liquid discharges from power plants. Some industry observers believe that the increased use of natural gas as a power plant fuel may help to reduce overall electric utility emissions of fine particulates, HAPs, and carbon dioxide. Increasing natural gas utilization through cofiring or fuel switching is one of the options that utilities are using to comply with NO_x and SO_2 emissions requirements of the CAAA.

3.7. Continuous Emissions Monitoring

A key aspect of the new CAAA is the requirement that plants prove their continued compliance to new emissions limits by installing continuous emissions monitoring systems (CEMs). The CAAA imposes new requirements for monitoring NO_x, SO_2, and CO_2 levels in a plant's exhaust gas stream. Affected plants typically must gather data from stack monitoring systems, gas analyzers, and the plant's data acquisition system and provide the data in a format approved by the EPA and state regulators. CEM systems must be in place by November 1993 for boilers affected by Phase I of the CAAA, and by January 1995 for plants impacted by Phase II.

4. Nuclear Regulatory Commission

The U.S. Nuclear Regulatory Commission (NRC) was formed in 1975, following the Energy Reorganization Act of 1974, to regulate the various commercial and institutional uses of nuclear energy, including nuclear power plants. The agency succeeded the Atomic Energy Commission (AEC), which was formed under the Atomic Energy Act of 1946 (13).

In 1954, Congress passed additional atomic energy legislation that redefined the U.S. atomic energy program by ending the federal government's secrecy concerning certain atomic energy information. The AEC was instructed by Congress to encourage widespread participation in the development and utilization of atomic energy for peaceful purposes. Following the 1954 Act, the AEC played three principal roles: (*1*) managing the U.S. atomic weapons program; (*2*) promoting the private use of atomic energy for peaceful purposes, such as power generation; and (*3*) protecting public health and safety from the potential hazards of nuclear-related programs. At that time, the AEC began establishing guidelines for nuclear power plant licensing as well as radiation protection guidelines.

When the NRC, headquartered in Rockville, Maryland, took over the responsibilities of the AEC in 1974, many of the AEC's research and development functions, particularly many covering new technology development and nuclear weapons production, were assumed by the U.S. Department of Energy. However, the NRC has maintained some research and developmental capabilities which are handled by the NRC's Office of Nuclear Regulatory Research.

In its responsibility to protect public health and safety, the NRC has three principal regulatory functions: (*1*) establishing standards and regulations; (*2*) issuing licenses for nuclear facilities and users of nuclear materials; and (*3*) inspecting facilities and users of nuclear materials to ensure compliance with NRC's requirements. These regulatory functions apply to both nuclear power plants and to other uses of nuclear materials, such as nuclear medicine programs at hospitals, academic and research activities, and manufacturing of products containing radioactive materials, eg, radiation sources found inside of smoke detectors or luminous watch dials.

The NRC issues licenses for the facilities noted and the operators of those facilities. Licenses may also be issued by individual state governments under NRC-approved regulatory programs. There are more than 8500 such licenses under the NRC's jurisdiction and approximately 15,000 under the jurisdiction of Agreement States, which regulate certain radioactive materials under agreements with the NRC. As of 1996, there are 109 licensed commercial nuclear power reactors in the United States, located at 71 sites in 33 states (see Nuclear reactors). However, several of these facilities are only partially constructed and further construction has been deferred. There are more than 5300 licensed nuclear power plant operators in the United States, each licensed for a specific reactor. Every operator must be requalified before renewal of a six-year license (14, 15).

The NRC has numerous offices and special committees, including more than 3000 staff members, which serve to advise and support the five commissioners appointed to staggered five-year terms by the President. The NRC's activities have been described in the *Nuclear Regulatory Information Digest,* 1993 (14).

The NRC relies primarily on reactor and facility inspections as the basis for licensee compliance with NRC regulations. Thus, the NRC personnel conduct from 10–30 routine inspections each year at every operating nuclear plant, depending on the activities underway at individual plants and problems which may occur. Inspection specialists, based in regional offices, review plant security, emergency planning, radiation protection, environmental monitoring, periodic testing of plant equipment and systems, fire protection, construction activities, and a number of other specialized areas.

NRC inspection teams issue inspection reports and provide these to the facilities, as well as designated public libraries located near operating plants and the NRC's Public Document Room for public disclosure. When inspections disclose violations of NRC requirements, the agency immediately issues a Notice of Violation, which requires the licensee to correct the problem and prevent recurrence. The licensee is given a deadline for planning and undertaking an acceptable response. For certain more serious or repetitive violations, the NRC may fine utilities or other licensees up to $100,000 per day for each violation. If inspection teams determine that a facility is operating in an unsafe manner, the NRC may issue orders requiring the shutdown of a facility or the modification of previous operating procedures.

4.1. Nuclear Waste

NRC defines high level radioactive waste to include (*1*) irradiated (spent) reactor fuel; (*2*) liquid waste resulting from the operation of the first cycle solvent extraction system, and the concentrated wastes from subsequent extraction cycles, in a facility for reprocessing irradiated reactor fuel; and (*3*) solids into which such liquid wastes have been converted. Approximately 23,000 metric tons of spent nuclear fuel has been stored at commercial nuclear reactors as of 1991. This amount is expected to double by the year 2001.

As of 1996, the bulk of spent fuel from nuclear power plants has been stored in specially designed water-filled holding pools at the reactor site. Some spent fuel is also stored at two off-site storage facilities, one in

Illinois and one in upper New York State (which no longer accepts waste). The water in these holding pools acts as a shield preventing release of radioactivity. At some plants, waste is beginning to be stored dry in heavily shielded, NRC-approved iron, steel, or concrete casks located on concrete pads.

Approximately 25–30% of a reactor's fuel is removed and replaced during planned refueling outages, which normally occur every 12 to 18 months. Spent fuel is highly radioactive because it contains by-products from nuclear fission created during reactor operation. A characteristic of these radioactive materials is that they gradually decay, losing their radioactive properties at a set rate. Each radioactive component has a different rate of decay known as its half-life, which is the time it takes for a material to lose half of its radioactivity. The radioactive components in spent nuclear fuel include cobalt-60 (5-yr half-life), cesium-137 (30-yr half-life), and plutonium-239 (24,400-yr half-life).

Although most spent fuel is stored on-site in the 1990s, a number of facilities are expected to run out of space within the next two decades. Some waste is still transported to the only active off-site storage facility located in Illinois. In addition, the federal government is trying to site a large centralized storage facility capable of handling all of the country's high level waste.

The NRC has developed special procedures for the handling, transportation, and storage of nuclear fuel because radioactivity can be a health hazard if not properly shielded. Spent fuel is typically transported by rail or truck in heavily shielded (Type B), sealed, thick metal shipping containers designed to withstand possible accidents, such as derailments or collisions, which may occur during transport. The NRC certifies that each shipping container meets federal requirements. The U.S. Department of Transportation sets the rules for transportation.

The NRC also imposes special security requirements for spent fuel shipments and transport of highly enriched uranium or plutonium materials that can be used in the manufacture of nuclear weapons. These security measures include route evaluation, escort personnel and vehicles, communications capabilities, and emergency plans. State governments are notified in advance of any planned shipment within their state of spent fuel, or any other radioactive materials requiring shipment in accident-proof, Type B containers.

In 1980, Congress determined that each state should be responsible for ensuring the proper handling and disposal of commercial low level nuclear wastes generated in their states. Regional disposal sites have also been established at Barnwell, South Carolina, and Ward Valley, California. These wastes are handled by licensed disposal facilities where they are packaged, placed in burial trenches, and covered with soil. Less than half of the low level nuclear waste produced annually in the United States comes from nuclear power plants. Low level nuclear power plant wastes include contaminated equipment, filters, maintenance materials, and resins used for cooling water purification.

5. Occupational Safety and Health Administration

The Occupational Safety and Health Act (OSHA) covers a broad range of issues relating to worker health and safety, many of which impact the power generation industry (16, 17). The Act sets standards designed to protect worker health and safety, particularly in industrial settings. The Occupational Health and Safety Administration, organized under the U.S. Department of Labor, implements and enforces OSHA standards and periodically updates policies governing worker health and safety.

The administration's rules cover many aspects of the power plant working environment, including specification of acceptable work garments and footwear, safety equipment and procedures, and work exposure to noise and substances which can negatively impact health. For example, the administration has stringent regulations regarding worker exposure to known carcinogens, such as asbestos, a naturally occurring, fibrous silicate material. This example is appropriate because asbestos-containing materials have been widely used in many existing power generation facilities, particularly for insulating materials surrounding piping, boilers, and other hot components. In addition, asbestos was widely used for fireproofing in or on building materials such as floor tiles, wallboards, and ceiling tiles. As power plants undertake maintenance and repair procedures, asbestos-containing materials encountered must be properly handled, removed, or encapsulated in place to comply with OSHA, EPA, and local rules.

In 1987, the administration tightened the permissible exposure limit (PEL) for asbestos from 2.0 fibers per cubic centimeter (f/cm^3) to 0.2 f/cm^3 based on an eight-hour, time-weighted average (TWA) exposure. In addition, more stringent notification, training, and supervision requirements have been established at that time, which are being further revised. In 1988, the administration amended the exposure standards to establish an excursion limit of 1.0 f/cm^3 as averaged over 30 minutes. In October of 1995, the TWA exposure standard was further reduced to 0.1 f/cm^3, but the excursion limit remained the same.

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STEVEN COLLINS
Empire State Electric Energy Research Corporation

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